Enhanced Energy System Transformation through Power and Heat Sector Coupling

A Modeling Analysis at the National and Urban Levels

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by
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Zusammenfassung

Die Energie- und Klimaschutzpolitik Deutschlands hat ein zukünftiges Energiesystem zum Ziel, welches ökologisch, ökonomisch und versorgungssicher ist. In den Jahren von 1990 bis 2017 konnte zur Vermeidung von Treibhausgasemissionen der Anteil erneuerbarer Energien in der Stromversorgung deutlich gesteigert werden. Jedoch kommen ein Großteil des Energieverbrauchs und der Emissionen auch aus den Energieversorgungssektoren für Wärme und Mobilität, in welchen der Transformationsprozess nur langsam voranschreitet.

Sektorenkopplung bezeichnet Technologien und Konzepte, die zwischen diesen Energieversorgungssektoren Synergieeffekte ermöglichen. Bei der Kraft-Wärme-Kopplung beispielsweise wird in einem einzigen Umwandlungsprozess Energie für zwei Verbrauchssektoren bereitgestellt. Im Gegensatz dazu ermöglicht Power-to-heat die Verwertung erneuerbaren Stroms in einem anderen Verbrauchssektor. In diesem zweiten Fall wird Sektorenkopplung als Alternative zum Ausbau des Übertragungsnetzes oder von Stromspeichern gehandelt, um mehr Systemflexibilität für die Integration fluktuierender Energiequellen, wie Photovoltaik oder Windenergie, bereitzustellen.

Diese Arbeit fokussiert auf die Strom- und Wärmesektorenkopplung durch Kraft-Wärme-Kopplung und Power-to-heat-Technologien, deren Entwicklungsstand und Umwandlungseffizienz sehr vielversprechend sind. Neben einem Überblick über den Hauptteil in den Kapiteln 2 bis 5 gibt Kapitel 1 auch eine kurze Einführung in Sektorenkopplung und ihre verschiedenen Erscheinungsformen. Kapitel 2 beginnt den Hauptteil mit einer Literaturübersicht über die Integration erneuerbarer Energien mittels Power-to-heat in der Energiesystemmodellierung. Kapitel 3 fokussiert auf die verschiedenen Kraft-Wärme-Kopplungs-Anlagen und deren Parametrisierung zur Energiesystemmodellierung. In Kapitel 4 werden diese Methoden in einem kombinierten Strom- und Wärmesektorenmodell auf nationaler Ebene für Deutschland angewandt. Darin wird endogen der durch Power-to-heat verursachte Stromverbrauch bestimmt und dessen Einfluss auf den Ausbau von Stromerzeugung und Stromspeichern analysiert. Kapitel 5 betrachtet dagegen näher auf urbaner Ebene das kombinierte Berliner Strom- und Fernwärmesystem im Kontext steigender erneuerbarer Stromerzeugung im nationalen Stromnetz und des Berliner Energie- und Klimaschutzprogrammes. Ein wesentliches Ergebnis dieser Arbeit ist eine wachsende Rolle von Power-to-heat zur Integration erneuerbaren Stroms und Dekarbonisierung. Ebenfalls reduziert diese Technologie den Bedarf an Stromspeichern. Im Gegensatz dazu ist die zukünftige Rolle von Kraft-Wärme-Kopplung fragwürdig und auch das Erfordernis von Wärmespeichern als Alternative zu Stromspeichern kann nicht bestätigt werden.

Schlüsselwörter: Stromsektormodellierung, Sektorenkopplung, Power-to-heat, Wärmepumpen, Wärmespeicher, Kraft-Wärme-Kopplung, Fernwärme

Abstract

Germany's energy and climate protection policy, the *energiewende*, has the aim of moving toward an energy supply that is ecologically sound, economically efficient and secure. In the years between 1990 and 2017, the power sector could considerably integrate renewable energy sources to avoid greenhouse gas emissions. However, substantial consumption and emissions also occur within other energy supply sectors, such as those of heating and mobility, whose transformation processes are stagnant.

Sector coupling refers to the incorporation of technologies and concepts that enables the exploitation of synergies between these different forms of energy supplies. In combined heat and power, for instance, outputs for two energy consumption sectors are simultaneously generated through a single energy conversion process. Or, electricity from renewable energy sources is used in other energy consumption sectors than power supply, such as by power-to-heat. In the latter case sector coupling is an alternative concept to power transmission expansion, for instance, or power storage that all increase system flexibility to integrate larger shares of non-dispatchable renewable energy sources like photovoltaics or wind power.

This thesis focuses on power and heat sector coupling through combined heat and power and power-to-heat technologies, as their maturity and conversion efficiency have proven to be promising. In addition to an overview of Chapters 2 to 5 of this thesis, Chapter 1 also provides a brief introduction to sector coupling and its various forms. Chapter 2 provides context for the three individual research articles that follow in the form of a literature review concerning the integration of electric renewable energy sources through power-to-heat in energy system modeling. Chapter 3 expands on the various types of combined heat and power plants and their parametrization for energy system modeling. In Chapter 4 the techniques laid out in Chapters 2 and 3 are applied in a joint power and heat sector modeling analysis on the national level with Germany as a case study. This work endogenously determines the increase in future electricity demand by power-to-heat and this technology's impacts on power generation and storage expansion. Chapter 5 examines an energy system at the urban level and assesses Berlin's joint power and district heating systems in the context of increasing penetration of the national power grid by renewable energy sources and Berlin's Energy and Climate Protection Program. Overall findings suggest that the role of power-to-heat is growing due to its propensity for renewable integration and decarbonization; furthermore, it decreases the need for power storage. In contrast, the future role of combined heat and power is questionable; further, the need for large-scale heat storage expansion as an alternative to power storage cannot be supported.

Keywords: power sector modeling, sector coupling, power-to-heat, heat pumps, thermal energy storage, CHP, district heating

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Andreas Bloeß
Berlin, den 27. November 2019

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Andreas Bloess
Berlin, November 27th 2019

Rechtliche Erklärung

Hiermit versichere ich, daß ich die vorliegende Dissertation selbstständig und ohne unzulässige Hilfsmittel verfasst habe. Die verwendeten Quellen sind vollständig im Literaturverzeichnis angegeben. Die Arbeit wurde noch keiner Prüfungsbehörde in gleicher oder ähnlicher Form vorgelegt.

Andreas Bloeß
Berlin, den 27. November 2019

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List of Abbreviations

AEA	Atomic Energy Act
AEL	alkaline electrolysis
AS	air source
ASHP	air source heat pump
BAU	business-as-usual
BECP	Berlin Energy and Climate Protection Program
BEV	battery electric vehicle
BHKW	cogeneration unit (CU), German: *Blockheizkraftwerk*
BNA	German Federal Network Agency, German: *Bundesnetzagentur*
BP	back-pressure steam turbine
BT	battery
CAPEX	capital expenditures
CB	condensation boiler
CC	combined-cycle gas turbine
CCBP	combined-cycle back-pressure CHP
CCEC	combined-cycle extraction-condensation CHP
CCOT	combined-cycle oil turbine
CCTS	carbon capture, transport, and storage
CH_3OH	methanol
CH_4	methane
CHD	Constant Heat Demand
CHP	combined heat and power
CM	condensation mode
CO	carbon monoxide
CO_2	carbon dioxide
COP	coefficient of performance
COPEX	cost per unit of exergy production
CSP	concentrated solar power

CU	cogeneration unit
DH	district heating
DHB	district heating boiler
DHD	Decreasing Heat Demand
DHEB	district heating electrode boiler
DHW	domestic hot water
DSM	demand side management
DSO	distribution system operator
DVGW	German Technical and Scientific Association for Gas and Water, German: *Deutscher Verein des Gas- und Wasserfaches*
EB	electric/ electrode boiler
EC	extraction-condensation steam turbine
EHP	electric heat pump
EIA	Energy Industry Act
ENTSO-E	European Network of Transmission System Operators for Electricity
ETS	emission trading system
EU	European Union
F2H	fuel-to-heat
FC	fuel cell
FEC	final energy consumption
GAMS	General Algebraic Modeling System
GB	gas boiler
GDP	gross domestic product
GEHP	gas-engine heat pump
GHG	greenhouse gas
GS	ground source
GSHP	ground source heat pump
GT	gas turbine
GTCHP	gas turbine CHP
H_2	hydrogen
HHKW	wood-fueled combined heat and power (CHP), German: *Holzheizkraftwerk*
HKW	combined heat and power (CHP) plant, German: *Heizkraftwerk*

HP	heat pump
HRB	heat recovery boiler
HS	heat storage, same as TES
HT	hydro turbine
HTES	high temperature electrolysis of steam
HW	heat-only plant, German: *Heizwerk*
Hy2H	hybrid-to-heat
IH	individual heating
LNG	liquefied natural gas
LP	linear program
MHKW	waste incineration combined heat and power (CHP), German: *Müllheizkraftwerk*
MILP	mixed-integer linear program
NLP	non-linear program
fixed O&M	fixed operation and maintenance costs
variable O&M	variable operation and maintenance costs
OCOT	open-cycle oil turbine
OPEX	operational expenditures
OPSD	Open Power System Data
P2C	power-to-chemicals
P2G	power-to-gas
P2H	power-to-heat
P2L	power-to-liquid
P2M	power-to-materials, same as P2C
P2V2P	power-to-vehicle-to-power
P2V	power-to-vehicle
PEMEL	proton exchange membrane electrolysis
PHEV	plug-in hybrid electric vehicle
PS-only	Power System-only
PSP	pumped storage plants
PV	photovoltaics
QP	quadratic program
REA	Renewable Energy Act

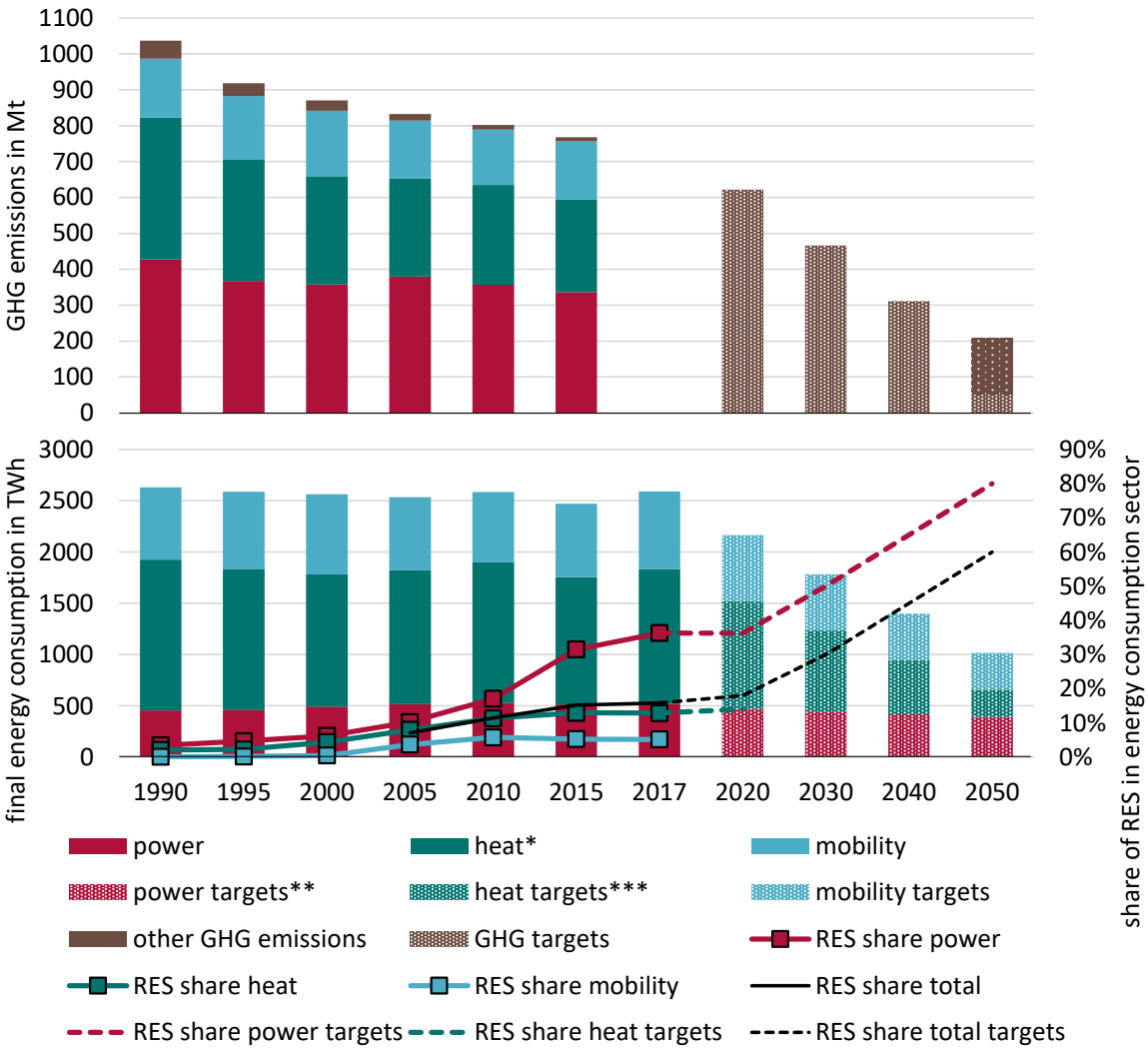
REB	residential electric boiler
RES	renewable energy source
vRES	variable renewable energy source
RHB	residential heat boiler
ROR	run-of-river
S2H	solar-to-heat
SETS	smart electric thermal storage
SH	space heating
ST	steam turbine
TES	thermal energy storage
TSO	transmission system operator
UK	United Kingdom
V2P	vehicle-to-power
WT	wind turbine
WPoff	wind power offshore
WPon	wind power onshore

Enhanced energy system transformation through power and heat sector coupling

1 Introduction

In 2010, the German Federal Government announced its long-term vision for a climate protection and energy policy. It aims at achieving substantial reductions in greenhouse gas (GHG) emissions, energy consumption, and growth in energy production utilizing renewable energy sources (RESs) by 2050 (BMWi and BMU, 2010). However, major legislative events had previously occurred, such as the 1998 reform of the Energy Industry Act (EIA), which enforced competition among electricity suppliers, or the Renewable Energy Act (REA) of 2000, which promoted the large-scale deployment of RES technologies (Hake et al., 2015). Likewise, later developments such as the 2011 political decision to phase out nuclear energy by 2022, are by now considered to be part of the *energiewende* policy in Germany (Hirschhausen, 2014). With all the political measures it has undertaken toward the objectives of the *energiewende*, the German Federal Government claims to be in the process of establishing a future energy supply system that is economically efficient, ecologically sound, and includes security of supply.

In terms of final energy consumption, the major sectors in Germany are those of power, heat, and mobility. Figure 1.1 depicts how these three final energy demands developed between 1990 and 2017. During this time span, the total consumption level stayed relatively constant and the structure between the three sectors barely changed. In 2017, the heating sector accounted for about 51% of total consumption (ca. 2,600 TWh_{th}), the mobility sector for 29% and the power sector for 20%. Also depicted is the share of RES in each sector. While there are no striking developments in the heat and mobility sectors, the rise from 3% in 1990 to 36% in 2017 in the electricity supply is often highlighted in public debate as the success story of the *energiewende*. Additionally, Figure 1.1 indicates the sectors' contribution to Germany's greenhouse gas emissions and reveals that, indeed, the power sector has the highest share at 43% in 2017 versus the heat and mobility sector with 34% and 22%, respectively. Furthermore, Figure 1.1 projects some of the most significant future targets concretely formulated by the government's climate protection and energy policy. As illustrated, greenhouse gas emissions should be reduced to 20-5% by 2050 compared to the 1990 levels. Gross power consumption should be reduced to 75%, and primary energy consumption in buildings to 20% compared to 2008 levels, and final energy consumption for mobility to 60% compared to 2005 levels. Interestingly, the policy does not further specify targets of power consumption in case new substantial electricity demand appears due to large-scale deployment of electric heating or electric mobility. The share of RES in the power sector should rise to 80% by 2050. The share of RES in all three sectors together is supposed to amount to 60% of gross final energy consumption in the long term. These figures indicate that the power sector plays a special role in energy consumption. First, it is the most emission intensive and hence crucial for the emission reduction objective.



* For the sake of simplicity, all final energy and greenhouse gas (GHG) emissions other than those of electricity or mobility are attributed to heating.

** Future targets are in reality formulated for gross electricity consumption. However, for the sake of simplicity, targeted reduction rates are applied here to final electricity consumption.

*** Future targets are in reality formulated for primary energy demand of buildings. However, for the sake of simplicity, targeted reduction rates are applied here to the entire final heat energy consumption.

Figure 1.1: Development of Germany's energy consumption sectors, its greenhouse gas (GHG) emissions, and future governmental targets.

Source: Based on BMWi (2018a,b,c).

Second, its sector target of an 80% share of RES is over-proportional compared the mere 60% share over all sectors together, indicating that the power sector should contribute a higher degree of technical transformation to the *energiewende*.

1.1 Motivation

Assuming that access to biomass will continue to be limited in the future and that Germany cannot further expand its hydro power generation, power sector transformation will be reliant on the expansion of power generation through photovoltaics (PV), wind onshore, and wind offshore capacity. These forms of power generation remain the only emissions-free and renewable energy technologies that constitute expandable resources for the German energy supply. These technologies, as well as hydro power from run-of-river, belong to non-dispatchable power generation technology, since their short-term availability depends on favorable meteorological conditions. Moreover, they are the only technologies that directly transform their primary energy source without intermediate conversion into heat energy, into the qualitative highest product of energy supply – electricity. The advantage of this characteristic is that, firstly, electric energy is easily transported over long distances without substantial losses and, secondly, it can be easily transformed to any other form of usable energy at its destination. The downside of electric energy is that it cannot be easily stored; further, the non-dispatchability of these technologies requires auxiliary technology to enhance flexibility and hence, to maintain at any time the necessary instantaneous short-term balance of power generation and demand in the transmission grid.

Figure 1.2 shows Germany's quarter-hourly residual load duration curve from 2018, where non-dispatchable generation accounted for more than 27% of total power generation. The residual load corresponds to the difference between the power demand load and non-dispatchable power generation. If the residual load is positive, the remaining demand must be covered by dispatchable power plants, such as fossil or biomass-fueled plants.[1] In the case of a negative residual load, a use must be found for the surplus produced by non-dispatchable power generation. The duration curve is obtained by ordering all residual loads of a year in descending order. The occurrence of negative residual loads is expected to increase with an increasing share of non-dispatchable power generation, which is achieved by expanding the capacities of wind and PV power generation. Figure 1.2 also shows the residual load duration curve with a hypothetical system penetration of 80% non-dispatchable power generation. The 2018 curve bends down, so that also negative residual loads occur. For this shifted curve, the area A amounts to the total yearly electric energy surplus. By means of auxiliary technology providing the necessary flexibility, such as storage, this amount of energy is ideally shifted to the area B, which is equal to area A in surface area. In this ideal shift of surplus energy, the auxiliary technology would achieve three types of savings: it reduces, first, the variable costs of conventional base load power generation; second, elevated variable costs of peak load power generation; and,

[1] Note not even biomass plants based on biogas processing are dispatchable either, if they do not possess biogas storage, which they usually do not. In contrast, plants fueled by solid biomass are comparable to coal plants in this regard.

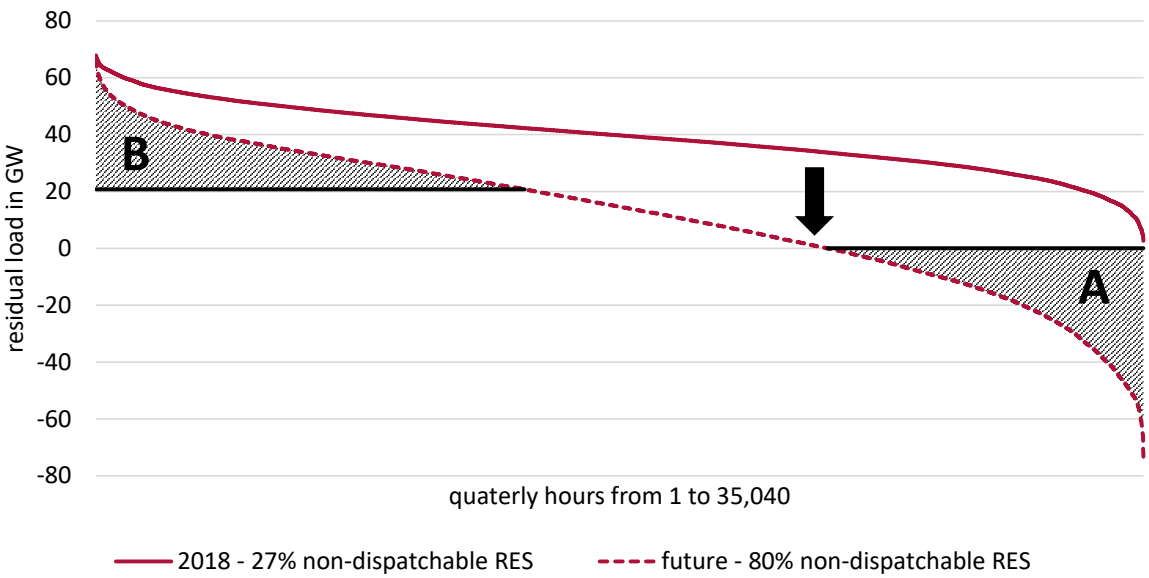


Figure 1.2: Germany's quarter-hourly residual load duration curve from 2018 with 27% and hypothetically with 80% non-dispatchable renewable energy sources.

Source: Own depiction based on data by ENTSO-E (2019) inspired by Zerrahn, Schill, and Kemfert (2018).

third, costs for the provision of peak load capacity (Zerrahn, Schill, and Kemfert, 2018). This shift is unlikely to be this perfect in reality. Area B would be certainly smaller than area A, since the auxiliary technology would bear some efficiency losses. Furthermore, the auxiliary technology will certainly not be operated in such a precise way due to lack of perfect foresight.

In Germany, power generation through RES is promoted through several instruments. RES generators either benefit from a priority feed-in, in which the transmission system operator (TSO) pays them a favorable fixed feed-in tariff and is responsible for selling this power feed-in at the power exchange, or they benefit from financial incentives to manage the commercial transactions themselves. This priority feed-in of RES for electricity requires conventional dispatchable power generation to adapt physically and economically to RES power generation in the short term. This adaptation requires increasing efforts the more the power system is penetrated by variable renewable energy source (vRES).[2] While in the past, the demand load and occasional contingencies of conventional generators were the only sources of insecurity, fluctuating weather conditions of wind and solar radiation have become additional sources of insecurity in the system with increasing vRES penetration. The TSOs apply a range of instruments to provide the usual ancillary services, such as control reserve, loss energy, and other services, as well as instruments to maintain

[2]This work uses the terms renewable energy source (RES) and variable renewable energy source (vRES). The latter is used when emphasizing the fluctuating, that is, not-dispatchable, nature of RES and is more narrow, since not all RES depend on current weather conditions.

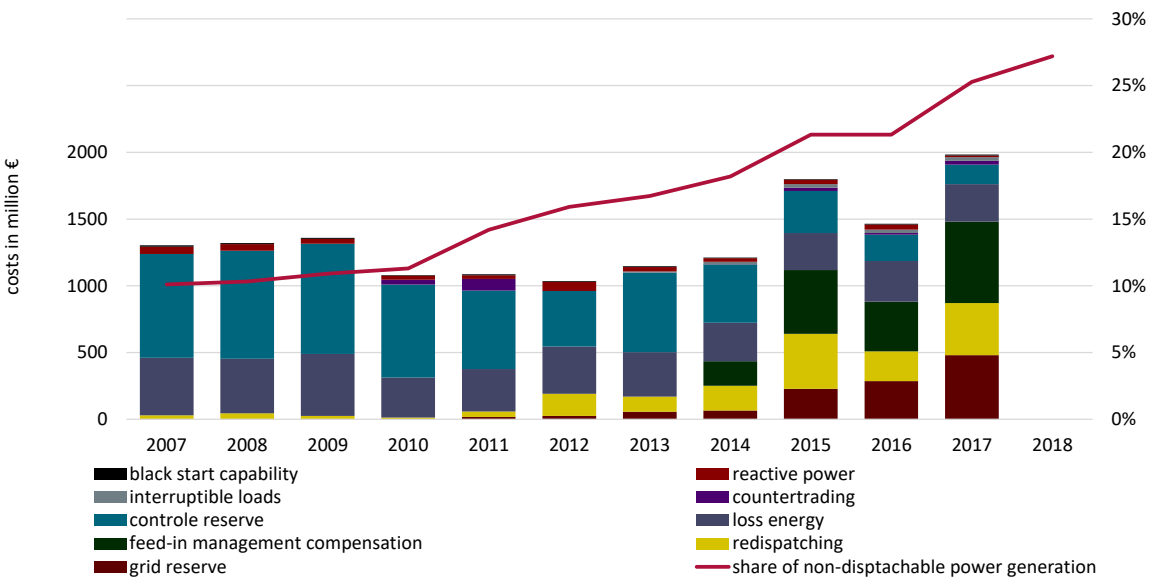


Figure 1.3: Development of costs for power network ancillary services and system security in Germany.

Source: Own depiction based on data from BNetzA and Bundeskartellamt (2018) with reports from 2006 to 2018 and AGEB (2018).

system security, such as redispatching, countertrading, grid reserves, and forced curtailment of RES generators. Figure 1.3 illustrates how the costs for these various instruments developed between 2007 and 2017 over the course of increasing system penetration with non-dispatchable power generation. A clear pattern of increasing costs for these instruments with an increasing share of non-dispatchable power generation cannot be detected. In fact, costs for ancillary services, in particular for control reserve, could be decreased partly through active trading of the TSOs at the intra-day power market. Instead, since 2012, rather other costs, such as those of redispatching, grid reserve, and feed-in management compensation payments for curtailment of RES generators have gained importance. This changing cost structure can be interpreted as part of the ongoing learning process of the TSOs on how to cope with the new sources of insecurity.

Nevertheless, the efficient use of RES and maintenance of system security will largely depend on the availability and integration of auxiliary technology that will provide the necessary system flexibility. P. D. Lund et al. (2015) highlight six technical solutions that provide flexibility to power systems: (i) strengthening transmission for better spatial smoothing of load and generation; (ii) various energy storage technologies for temporal smoothing; (iii) several variations of demand side management (DSM) to accommodate the consumer's demand behavior; and (iv) faster responsiveness of conventional power generators to follow residual load and to serve as back-up capacity. In order to avoid (v) the curtailment of RES generators as a last resort of flexibility, since sunk costs in RES capac-

ity would not be efficiently exploited; (vi) sector coupling can ensure the beneficial usage of surplus electricity in other energy consumption sectors. Throughout this chapter, sector coupling refers to those technologies that combine either the power and heat sectors, such as combined heat and power (CHP) or power-to-heat (P2H), the power and gas sectors by means of power-to-gas (P2G), the power sector and individual transportation by means of power-to-vehicle and vehicle-to-power[3], or the power sector and the production of basic industrial chemicals. Zerrahn, Schill, and Kemfert (2018) analyze the cost-minimized optimal mix between storage capacity[4] and RES curtailment for a stepwise increase in minimum penetration from non-dispatchable power generation in Germany. In a second step, they also incorporate an unspecified generic power-to-X technology (representing an unspecified mix of the aforementioned sector coupling technologies with the exception of CHP) with a conversion capacity of $50\,\mathrm{GW_{el}}$ and an annual energy demand of $100\,\mathrm{TWh_{el}}$ in the German power system. The results of this analysis as depicted in Figure 1.4 show a significantly reduced requirement for curtailment and energy storage capacity for elevated system penetration levels with non-dispatchable power generation. For instance, a power system covering 80% of its conventional electricity demand with non-dispatchable RES would reduce RES curtailment from 16% to 5% and its requirement for energy storage volume from $460\,\mathrm{GWh_{el}}$ to $240\,\mathrm{GWh_{el}}$, when sector coupling has been additionally incorporated.

1.2 Research questions

This work shall further investigate the role of sector coupling as an alternative option for flexibility in the German energy system; notably, power and heat sector coupling. To this end, this thesis presents four different research articles, each assigned to a separate chapter: Chapter 2 *Power-to-heat for renewable energy integration: A review of technologies, modeling approaches, and flexibility potentials* (Bloess, Schill, and Zerrahn, 2018), Chapter 3 *Modeling of combined heat and power generation in the context of increasing renewable energy penetration* (Bloess, 2020), Chapter 4 *Impacts of heat sector transformation on Germany's power system through increased use of power-to-heat* (Bloess, 2019a), and Chapter 5 *Urban energy transition: The impact of increasing renewable energy sources on the Berlin power and heat energy systems* (Bloess, 2019c). They all examine joint power and heat supply systems with an emphasis on CHP, power-to-heat, and heat storage technologies. While the first article comprises a literature review of power-to-heat and its energy system modeling, the other three chapters are modeling exercises performed by the author.

Chapter 2 draws on the fact that the benefits and challenges of various power-to-heat options in power systems with increasing penetration by non-dispatchable RES are just beginning to be understood. The literature is still rather varied, as existing power system and market models have been extended and new ones are continuously developed with wide variations concerning the applied technologies, geographical scope, and time hori-

[3]Power-to-vehicle and vehicle-to-power are also known as grid-to-vehicle-to-grid concept.

[4]Storage capacity refers here to the storage energy volume in MWh and also to the capacity for charging and discharging in MW.

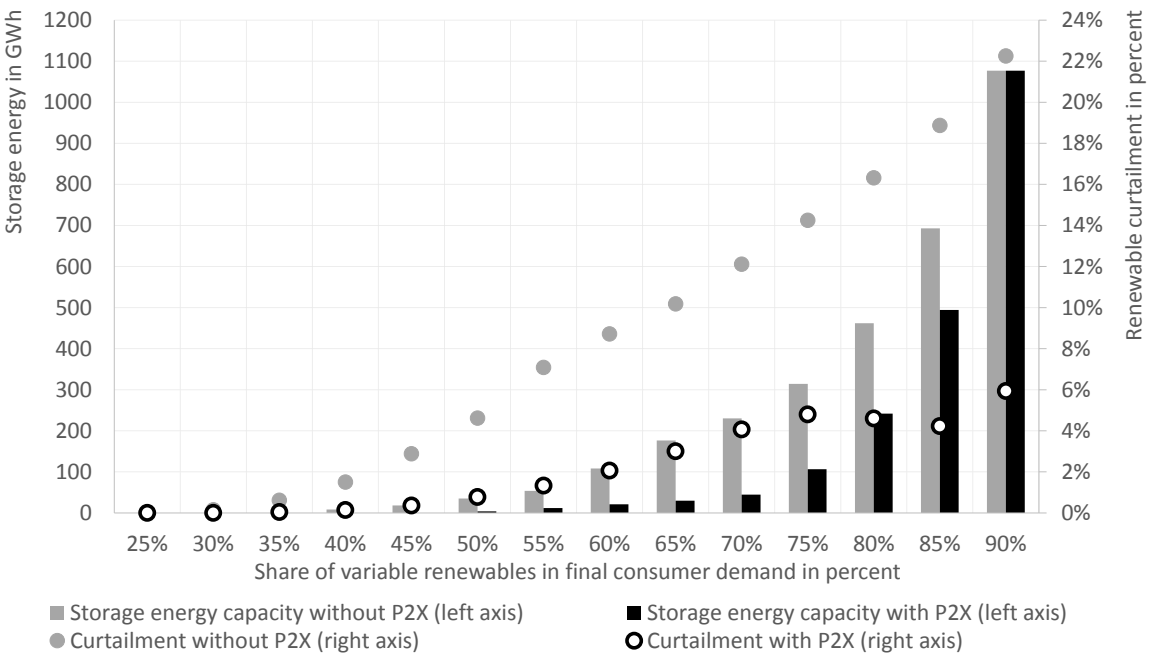


Figure 1.4: Comparison of cost-optimal electricity storage capacities and renewable curtailment with and without additional annual power-to-X electricity demand of 100 TWh_{el}.

Source: Zerrahn, Schill, and Kemfert (2018).

zons. Thus, the aim of this articles is to provide a structured overview of international peer-reviewed literature of model-based analysis of the different power-to-heat technologies. In particular, the review juxtaposes the different scopes, research questions examined, and employed methodologies. Concerning the latter, the review also highlights outstanding modeling approaches. Moreover, it synthesizes common findings in the model-based literature.

Chapter 3 focuses on the role of CHP plants in power and heat systems increasingly penetrated by vRES for electricity. This article has two objectives: first, it introduces the technical particularities of various CHP plant types and their basic parametrization to be applied in energy system models; second, it provides a differentiated view of the role and efficiency of CHP in systems increasingly penetrated by vRES and juxtaposes CHP with uncoupled power and heat generation. By applying a techno-economic cost-optimizing investment and dispatch model on six stylized energy systems, the most significant types of CHP plants are examined individually. Thus this analysis addresses four challenges to CHP in the context of vRES penetration that is increasing toward 100% of electricity demand. These challenges are as follows: (i) the variability and insecurity in covering the residual power load due to changing availability of RESs are added to the ever-changing power and heat load variations on the demand side in the short term; (ii) as the capacity

expansion of vRES increases, the residual power loads decrease in the long term, which reduces the numbers of cases with high residual power shares, whereas the same heat loads must be covered; (iii) alternatively to more flexible and better fitted operational fields of CHP, other flexibility options evolve, such as curtailment of vRES, power and heat storage, or sector coupling technologies; and (iv) still other heating technologies exist, such as ground source heat pumps (GSHPs) in combination with vRES for electricity or with highly efficient and flexible combined-cycle gas turbine (CC) power plants. Each of the six systems shows how one particular type of CHP technology adapts to an optimized technology mix.

The article contained in Chapter 4 has two objectives: first, it employs an already existing dynamic long-term power-only sector partial equilibrium model for the European market subjected to an increasingly tightening carbon dioxide (CO_2) emissions constraint, named dynELMOD by Gerbaulet and Lorenz (2017), and extends it to both the German individual and district heating supplies. This reveals differences in the analyses of power system development according to whether heat energy supply has been methodologically incorporated or omitted. Second, by means of this extended model, dynELMOD+heat, Germany's potential increase in electricity demand through power-to-heat technology is analyzed using both an ambitiously reduced heat energy demand and a constant heat energy demand. This analysis provides lower and upper estimates for additional electricity demand and its impact on the required RES and storage capacity expansion in Germany up to 2050.

The article presented in Chapter 5 analyses the urban power and district heating (DH) systems in the state of Berlin under the state government's Energy and Climate Protection Program (BECP). Special focus is put on the city's energy system development under the constraints of the following: first, the increasing penetration of RES for electricity within the national power grid up to 2050; and, second, the integration of alternative heat sources under a supposed technical transformation of the city's district heating infrastructure toward lower supply and return temperature levels. The objective is to evaluate the future role of Berlin's CHP plants and district heating infrastructure and the extent to which they are consistent with Berlin's energy policy. This article further examines how alternative technologies, such as conventional and RES power plants, heat-only plants, power-to-heat as well as power and heat storage, form an optimal technology mix to cover the city's future power and heat demands under the emissions constraints of the Berlin Energy and Climate Protection Program (BECP) and in a business-as-usual (BAU) scenario without these constraints. In both scenarios, several simulations are computed in which the RES penetration in the national power system is increased and the supply and return temperature in the Berlin district heating system decreased. Endogenously determining the temperature levels in the district heating network permits, first, the imposition of more realistic technical constraints on the operation of ground source heat pumps, solar-thermal collectors and thermal energy storage compared to other energy system modeling and, second, to analyze effects on their expansion and employment when lowering maximum supply and return temperature levels.

The remainder of this chapter proceeds as follows: the following Section 1.3 expands

upon the term "sector coupling", presents its various forms, and a summary of its features. Section 1.4 provides a comparative overview of the four articles of this thesis, whereas the conclusion, Section 1.5, summarizes the insights gained.

1.3 A primer to sector coupling

Unlike the elaborate accounts of transmission grid expansion, power storage, DSM, or RES curtailment, the term "sector coupling" (German: *Sektorenkopplung*[5]) is not mentioned once in the swiftly growing German legislation related to climate and environmental protection and energy. Sector coupling achieves a more prominent role rather late in the German *Climate Protection Plan 2050* from 2016. Here, a three-step concept for climate protection in the energy sector is formulated: first, significant and lasting reduction of demand in all energy consumption sectors; second, direct employment of RES in all sectors as far as is possible and economically sound; and, third, efficient use of electricity from RES for heating, mobility and industry (sector coupling) (BMU, 2016). Without explicitly mentioning the term "sector coupling", the idea as such is referred to for the first time in the amended 2017 version of the Energy Industry Act and is even formulated there as one of the *"Principles of the Electricity Market"* in §1a (3):

> "It should be in particular worked towards a more flexible supply and demand. A competition between efficient and flexible production systems, systems for storing electrical energy and loads, an efficient coupling of the heat and the transport sector with the electricity sector as well as the integration of charging infrastructure for electric vehicles into the electricity supply system to reduce the costs of energy supply, enabling the transformation to an environmentally responsible, reliable and affordable energy supply system and ensure security of supply." (Adam, 2018; BMJV, 2017)

In this regard, sector coupling is clearly meant to contribute to an economical, ecological and secure energy supply system. If the term "sector coupling" were explicitly indicated in German legislation, it would be likely to find a detailed definition there as well. Yet, there is none. Such a clarification can be useful, since energy always requires conversion from one form into another. Yet since this general notion of energy conversion is trivial and not intended in this context, it is useful to employ a distinction that is more narrow. For instance, it would be absurd to speak of power and transport sector coupling as electricity is used for electric railroad transport. The continuous supply of a moving train with massless electric energy by means of a cable along the railroad has certainly proven to be more economical and practical than transporting tons of coal to be burnt in the train ovens. Moreover, for production of cooling, electricity is usually used; this would never be considered to be a power and cooling sector coupling, because alternative techniques are certainly far less practical. On the other hand, sector coupling must not be constrained by

[5] In German circles of experts usually the term *Sektorkopplung*, with *Sektor* in singular, is used. However, only plural can be correct, since there must be at least two elements, when speaking of coupling.

too narrow a definition, as it is, for instance, by the Federal Ministry for Economic Affairs and Energy: "[...] Additionally helps the employment of electricity from renewables to push forward the *energiewende* in the other sectors. If this clean electricity is used in order to reduce the employment of fossil energy carriers, one speaks of *sector coupling*."(BMWi, 2016)*. The German Technical and Scientific Association for Gas and Water (DVGW) has a broader view of the term: "The idea of *sector coupling* is to combine the infrastructures of electricity, heat, gas, and mobility. This enables the increased use of renewable energies and its contribution to decarbonization beyond the electricity sector, for example, in households, the service, and industry sectors as well as in transportation." (DVGW, 2016)* The approach taken by the ministry aims for an energy carrier substitution in the sense of electrification toward an all-electric system, whereas the approach taken by DVGW only emphasizes the integration of infrastructures. Hence, the former approach can be seen as a very specific case of the latter approach, which is far more general. None of these definitions expatiates on the synergies that can be achieved through sector coupling.

Indeed, sector coupling corresponds to the phenomenon of increased deployment of RES and must always be seen in connection with it. To be more specific, this applies only to RES technologies such as PV, wind, and hydro power generation, as these are the only technologies that directly transform their primary sources into electricity. In the past, electricity was traditionally produced in conventional power plants, which conducted several energy conversions to finally attain the highest quality of usable energy consisting of 100% of exergy through electricity. Through combustion, energy chemically stored in the fuel was transformed to heat energy carried by steam, which was in turn transformed into motion energy in steam turbines in order to drive electric generators toward producing electricity. All these conversions together amount to significant energy losses, reducing the overall efficiency and hence, increasing its production costs. Consequently, the further use of electricity must be economically reasonable. Using this valuable electricity, for instance, to produce low temperature heat on a large scale, which is a comparably low-quality energy, would certainly be a careless destruction of exergy of the initial value of the fuel. If the final product in such an energy system is heat energy, the direct combustion of fuel without electricity generation appears to be reasonable and thus constitutes that system's traditional energy process. Only the large-scale deployment of PV and wind power generation can make it possible to consider using electricity in an unconventional way, i.e. for heating. Nevertheless, once capacities of non-dispatchable RES have been established, it is most reasonable to first use their generation potential to avoid costly fossil fuels and greenhouse gas emissions in conventional power generation before finding other purposes. Cogenerated power and heat in CHP plants can also be considered to be sector coupling. This form of sector coupling came into being independently from the rise of RES for electricity and has always been based on the exploitable synergy effect of additionally producing usable heat when generating electricity in a conventional steam-cycle.

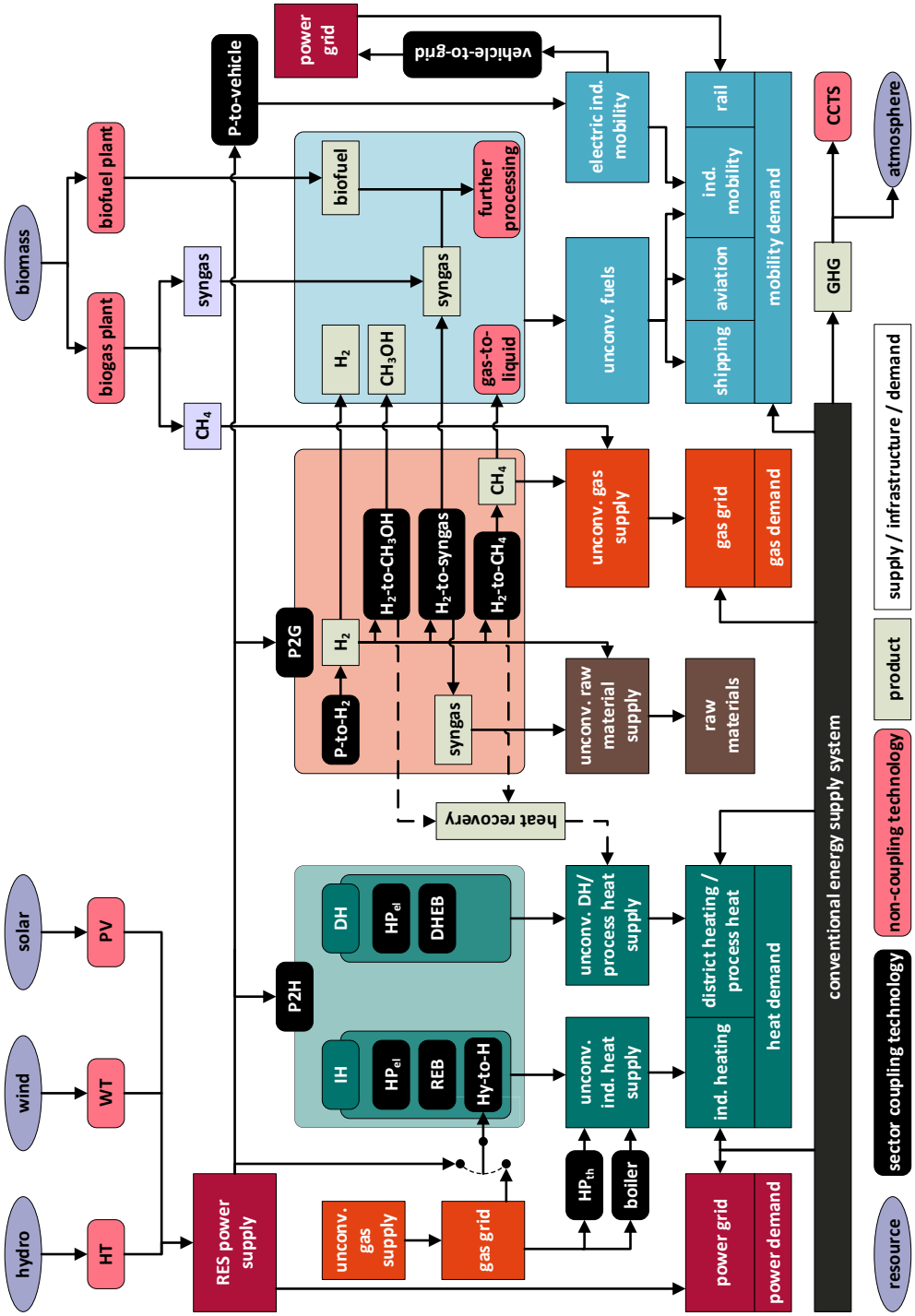
*Translation by the author.

1.3.1 Sector coupling technologies

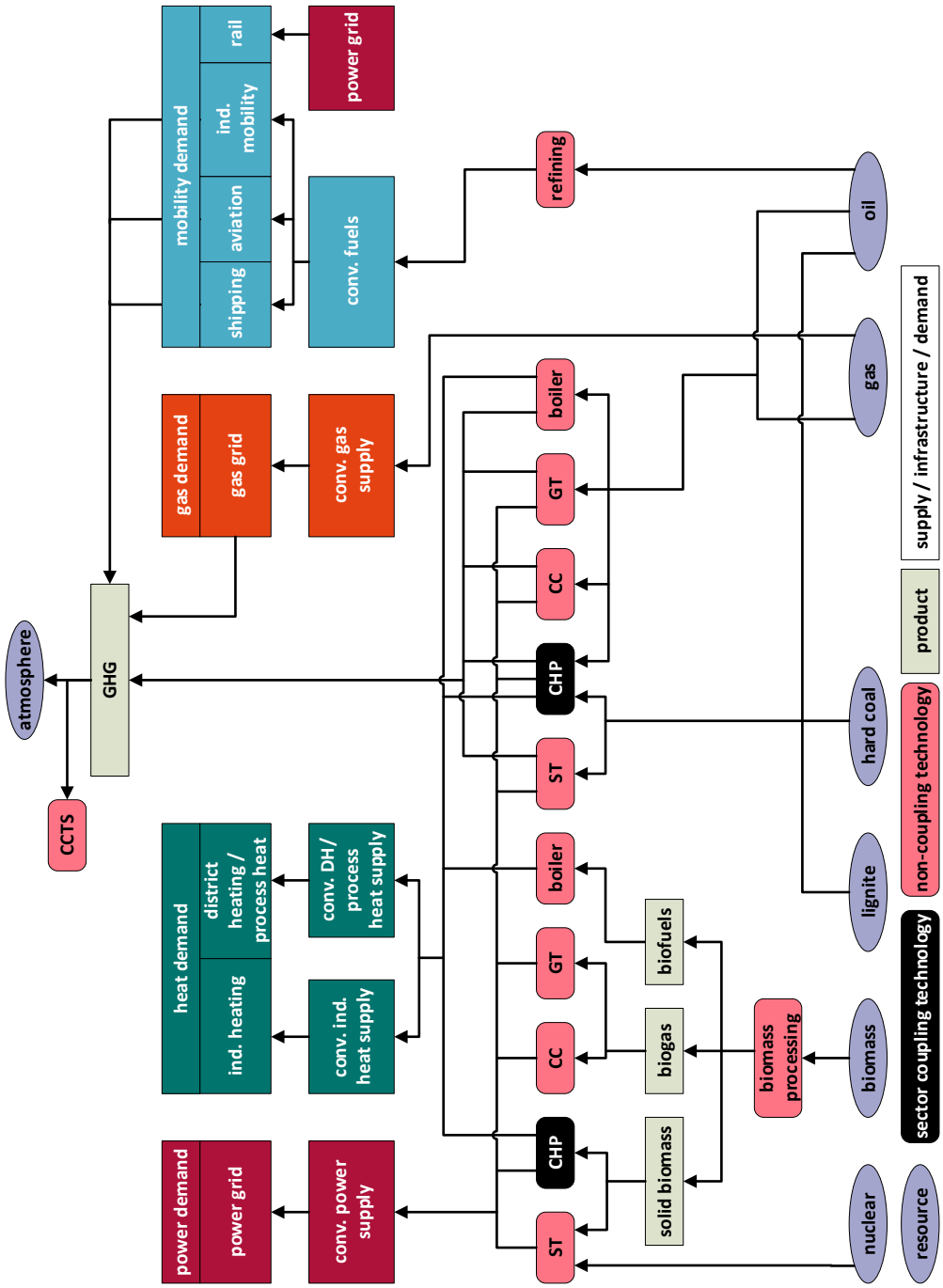
Figures 1.5a and 1.5b illustrate a conventional energy system that is mainly based on nuclear and fossil energy sources and a sustainable energy system based on RES, respectively. In the conventional energy system, CHP is the only sector coupling technology, whereas various sector coupling technologies play an integral part in the sustainable energy system. Germany's energy system as of 2019 still more resembles the conventional energy system in Figure 1.5a. Nevertheless, with increasing shares of PV and wind power generation, technologies from the sustainable energy system are incorporated. In the long run, Germany's energy system may come to fully resemble the latter illustration. Unlike in previous decades reaching back to the 1970's, wherein various "experts" stated the general impossibility of substantial shares of RES in the power system (Heymann, 1995), it is now widely recognized that there are no natural laws preventing an energy system that is 100% based on non-dispatchable RES. Instead, the focus of current political and scientific debate is how to most efficiently attain auxiliary technologies, as well as adequate institutions, and market designs which would enable such an energy system. Figure 1.5 highlights in black all the most relevant sector coupling technologies, which are addressed in the following.

Combined heat and power (CHP) can be considered to be a sector coupling technology because it generates two outputs simultaneously with electric and heat energy from an energy carrier as a single input. CHP plants have a capacity ranging from less than $100\,\mathrm{kW_{el}}$, referred to as micro- or μ-CHP, to several hundreds of $\mathrm{MW_{el}}$. The basic principle is to make use of heat that is generated as a side product through thermodynamic conversion processes instead of discarding it into the environment as in conventional power plants. Thus, depending on the type of technology, total fuel efficiencies of up to 70% to 90% can be reached in the optimal operation mode. While Figure 1.5a refrains from highlighting all the technical varieties of CHP technologies, the article *Modeling of combined heat and power generation* (Bloess, 2020) in Chapter 3 expounds these varieties, the technical coupling of power and heat output, as well as the conditions to reach such high fuel efficiencies. In principle, any steam-cycle based power plant must cool down and condensate the steam after expansion in the turbine; large parts of this energy can be reused in the form of low temperature heat. Waste heat in exhaust gas from gas turbine plants can also be used by means of a heat recovery boiler, and the same holds for combined-cycle power plants. Moreover, there are standardized small-scale cogeneneration units, fuel cells, or sterling motors that produce electricity and usable heat. All CHP technologies have the common requirement that the heat demand be in the near vicinity, since, unlike electricity, heat is difficult to transport over long distances without considerable losses. Hence, large scale CHP plants are normally connected to district heating networks in cities, on industrial sites which need process heat, or take the form of smaller-scale plants connected to local district heating networks.

Power-to-heat (P2H) uses electricity as an input to generate usable heat as an output either for individual heating (IH), district heating (DH), or process heat. The two basic technological approaches are either to use resistance heating in electric or electrode boilers



(a) Sustainable energy system with sector coupling.



(b) Conventional energy system.

Figure 1.5: The sustainable energy system with sector coupling technologies **(a)** and conventional energy system **(b)**.

or to drive the engines of electric heat pumps (EHPs). Electric boilers can heat water up to 100°C, which is sufficient for individual households. To reach higher temperatures in district heating, process heat or steam generation, rather electrode boilers are employed; both electric and electrode boilers achieve very high efficiencies of nearly 100%. In contrast, heat pumps (HPs) perform better in the low temperature levels, such as those needed for space heating (SH). As they pump heat from a useless low temperature level to an elevated temperature level from a source which is usually freely available such as environmental air (air source; AS) or heat from underground (ground source; GS), they essentially exploit a renewable energy source. A typical performance of a heat pump is the usage of one unit of electricity to harvest three units of air source or ground source heat energy, which leads to a coefficient of performance (COP) (sometimes referred to as efficiency) of four (400%). In Germany, electric heat pumps are usually employed for space heating or individual heating, preferably in well insulated buildings and/or in connection with floor heating, due to the lower supply temperature required. In principle, large-scale electric heat pumps for district heating purposes are also possible. This has already been demonstrated by utilities in Denmark or Sweden (VDE and ETG, 2015). To the best knowledge of the author however, there has been no such usage so far among German district heating utilities. Various methods of application of and research involving power-to-heat are summarized in the review article in Chapter 2 *Power-to-heat for renewable energy integration* (Bloess, Schill, and Zerrahn, 2018).

Power-to-gas (P2G) uses electricity as an input to produce gas that can be easily stored, transported, or directly made use of as an output. Power-to-gas is generally either considered to be a one-stage process, in which electricity is used to produce hydrogen gas (H_2) – the electrolysis, or as a two-stage process, in which the hydrogen gas is processed further into methane gas (CH_4) – the methanization. The first stage, power-to-hydrogen, is chemically represented by formula (1.1).

$$2\,H_2O \xrightarrow{\text{electrolysis}} 2\,H_2 + O_2, \qquad \Delta H_R^0 = +\,572\,\text{kJ/mol} \tag{1.1}$$

There are three common technical approaches to carry out electrolysis: (i) alkaline electrolysis (AEL); (ii) proton exchange membrane electrolysis (PEMEL); and (iii) high temperature electrolysis of steam (HTES). Among these, the AEL is the most mature technology with several commercially available products already in operation, whereas the HTES is still in an early research and development phase with low levels of maturity. However, the efficiency of AEL is lowest at 62-82% compared to the PEMEL (67-82%) and HTES (65-82%) (Sterner and Stadler, 2014). Compared to other storage systems, the efficiency of power-to-gas is generally low, especially when considering the cycle efficiency in a power-to-power storage, such as pumped storage plants (PSP) or batteries. In each of the three processes, considerable amounts of waste heat are produced. Any plant operator able to make commercial use of this heat energy can substantially increase the process efficiency. More potential for the application of this heat should be found for PEMEL and HTES due to their higher operational temperature level of 20-100°C and 700-1,000°C, respectively, compared to only 40-90°C of the AEL. With regard to conventional hydrogen production,

all these processes are far more costly and less economical. But when viewed rather as an auxiliary technology to enable the integration of RES, with two side products, i.e. heat and oxygen, electrolysis is a promising form of technology in the sustainable energy system that may avoid substantial curtailment of RES in the future. Hydrogen gas has a wide variety of uses in the chemical industry and can be used as a transport fuel or mixed into the methane gas transmission and distribution grids to a certain degree. Critics of hydrogen argue that no hydrogen infrastructure exists that would connect production and consumption via a pipeline network like in the natural gas sector. Concerning hydrogen as transport fuel they also raise the chicken-and-the-egg question, since hydrogen-fueled vehicles would not appear in the market before there are sufficient hydrogen fuel stations and vice versa (ibid.). Nevertheless, this argument is also valid for other propulsion alternatives and, in the long run, there may be no need for a hydrogen grid, since spatially dispersed fuel stations may produce hydrogen themselves and require only the power system infrastructure.

One alternative is to further convert hydrogen into methane gas in case no economical use can be found locally. The principle for this process is the Sabatier reaction as depicted by formula (1.2).

$$\mathrm{CO_2} + 4\,\mathrm{H_2} \longrightarrow \mathrm{CH_4} + 2\,\mathrm{H_2O}, \qquad \Delta \mathrm{H}_\mathrm{R}^0 = -165\,\mathrm{kJ/mol} \tag{1.2}$$

This second stage of power-to-gas sector coupling substantially reduces the overall efficiency and thus, should be avoided in future sustainable energy systems, if possible. The advantages of methane gas as an output is that it is better suited for storage and transport, necessary infrastructure for its use already exists, and it is more widely applicable when compared to hydrogen gas. As indicated by formula (1.2), methanization is a powerful exothermic reaction and must be cooled. Thus, any operator of a power-to-gas plant would aim to make use of this heat internally or to locate the plant close to an external local heat demand to exploit synergy effects. Since the process temperature level is high, at 200-600°C, the methanization process should be easily integrated into a heat supply system. Yet, as in any power-to-gas conversions, the intermittency of heat loads in practical operation must be taken into account.

Instead of producing methane gas, hydrogen can be used to produce syngas – a mixture of hydrogen (H_2) and carbon monoxide (CO) typically in the ratio of 3:1. In the petrochemical industry, syngas is a starting product for a huge variety of other products, especially fuels. According to the formula (1.3), carbon dioxide (CO_2) can be chemically reduced through the use of hydrogen. For a typical syngas mix, more hydrogen is combined with the product CO (Sternberg and Bardow, 2015).

$$\mathrm{CO_2} + \mathrm{H_2} \longrightarrow \mathrm{CO} + \mathrm{H_2O}\,, \qquad \Delta \mathrm{H}_\mathrm{R}^0 = -41\,\mathrm{kJ/mol} \tag{1.3}$$

Power-to-liquid (P2L) is another viable option as a supplementary process stage to hydrogen gas processes and as a means to provide liquid fuels to the mobility sector based on RES. Not all liquid fuels such as gasoline, diesel, or jet fuel, that can be technically produced from syngas or methane, are discussed here. Formula (1.4) illustrates the catalytic

synthesis of methanol (CH_3OH) from carbon dioxide and hydrogen, which is a powerful exothermic reaction.

$$CO_2 + 3\,H_2 \longrightarrow CH_3OH + H_2O, \qquad \Delta H_R^0 = -49\,\mathrm{kJ/mol} \tag{1.4}$$

Methanol can be directly used as a fuel, to blend other fuels, or as basic product for other chemical productions. Furthermore, also methane gas can be transformed to a liquid as liquefied natural gas (LNG) by means of a liquefaction plant. In several steps of consecutive compression, cooling under constant pressure, and adiabatic expansion, such a plant reduces its temperature to -162℃ and its volume to a six hundredth. In the future, such renewable based LNG could be used as shipping fuel, for example.

In the long term, a critical point for any further processing of hydrogen with carbon could become a non-fossil source of CO_2, since in a future decarbonized energy system fossil carbon is supposed to become scarce.

Power-to-gas-to-power is referred to when the energy system analysis is limited to the power-only system or when comparing the entire conversion cycle of power-to-gas respectively to a power-to-power storage system. The conversion of the unconventional methane gas produced by means of methanization back to electricity is carried out through conventional power generation technology. In contrast, omitting the methanization stage, hydrogen gas is either mixed into methane gas to some limited degree, or purely converted to electricity by slightly modified conventional power generation technology based on combustion or by means of hydrogen fuel cells. The cycle efficiency with the additional methanization is certainly very low. Therefore, from an economic point of view, this option remains merely theoretical for the time being.

Power-to-gas-to-heat is a theoretical option for now as well, but with certainly higher fuel usage efficiency in the final conversion stage compared to power generation. Also here, as with gas-fueled condensation boilers, conventional technology applies. An alternative form of technology that is discussed as an aspect of a comprehensive future energy system are gas-engine heat pumps (GEHPs). In combination with power-to-gas this represents an alternative to electric heat pumps with a strong focus on energy transport and storage in the form of gas. Unlike in an electric heat pump, which uses an electric motor to drive the compressor, a gas-engine heat pump's compressor is driven by a combustion engine. Its waste heat can be utilized at the site to provide additional heat energy. A smart design configuration uses the heat from the exhaust gas as well as the waste heat released from the engine cylinder jacket. The heat recovery allows for the effect of outdoor temperature on the gas-engine heat pump performance to be less pronounced than on the operation of an electric heat pump. Also, gas-engine heat pumps respond quickly, can dynamically adjust their operation, and, with their high energy efficiency, can help utilities reduce fossil fuel consumption. In terms of the entire power system, they can mitigate peak loads (Rosato, Sibilio, and Scorpio, 2013). Compared to an electric heat pump, however, their coefficient of performance is less than half as high (Kaltschmitt, Streicher, and Wiese, 2014).

Hybrid-to-heat (Hy2H) refers to any technology that combines the use of a conventional

chemical energy carrier to produce heat with power-to-heat. For instance, individual household heating systems can combine an electric heat pump with a condensation boiler fueled by gas or oil, or a condensation boiler with an electric heating rod. Large industrial consumers that constantly require process heat could also easily switch in the short term between the consumption of either gas or electricity when equipped with a gas boiler and an additional electric boiler for the same purpose. district heating utilities with gas-fueled heat-only plants and electrode boilers connected to their heating network implicitly possess such a hybrid-to-heat technology. In sector coupling energy systems, this technology permits consumers or system operators to switch freely between gas or electricity as an input to generate heat as output. From the viewpoint of a comprehensive energy system, this form of technology has powerful implications for the power system's flexibility to cope with variability in power generation from non-dispatchable generators like PV and wind turbines. If such capacities are conveniently distributed within the power grid, they can make use of power surpluses and avoid congestions in the grid by conducting what is referred to as *"virtual methanization"*. Virtual methanization is understood as staving off a power-to-gas process with physical conversion of electrolysis and consecutive methanization. Hybrid-to-heat permits a gas consumer to temporarily substitute its usual methane gas consumption with electricity consumption without experiencing any losses in comfort. This substitution effect enables the retention of the amount of gas usually consumed within the gas storage and transport infrastructure and hence, represents a virtual transformation of power into gas without the conversion losses connected to power-to-gas technology. Only when this flexibility potential is totally exploited within a future energy system could a larger role-out of power-to-gas be justified. Before that, however, power-to-heat should play a bigger role than power-to-gas on the basis of its more economical conversion form. In this regard, virtual methanization enabled by hybrid-to-heat represents a true bi-directional sector coupling between the power and gas sectors. In contrast, power-to-heat is only a uni-directional sector coupling from the power to the heat sector.

Power-to-vehicle-to-power (P2V2P) represents another bi-directional sector coupling, since the usual conversion losses are tenable compared to power-to-gas-to-heat or power-to-gas-to-power. Power-to-vehicle describes the charging process of batteries within battery electric vehicles (BEVs) or plug-in hybrid electric vehicles (PHEVs). This way, power surpluses as a result of non-dispatchable RES generation can be utilized as well as be temporally shifted, and the combustion of fossil fuels in the mobility sector can be substituted. In addition to a negative reserve for the power system, electric vehicles can also provide a positive reserve when the reinjection of electricity from the vehicle batteries to the power grid is taken into consideration. A huge idle electric car fleet connected to the power grid thus represents a substantial power storage that can provide power system services, when the means of control are available to TSOs and distribution system operators (DSOs). In this regard, power-to-vehicle transforms electricity as an input to optional propulsion for individual mobility as an output.

Power-to-chemicals (P2C) denotes an umbrella term for all kinds of processes in which the technology of power-to-gas is employed to make use of electric surplus power to produce

Table 1.1: Comparative overview of characteristics and features of various sector coupling technologies.

sector coupling			technology	characteristics / features inputs	outputs	efficiency	uni-/bi-directional	technology maturity	output transportability	output storability short-/ medium-/ long-term	ancillary service / flexibility	output usability	primary energy substitution	cost optimization
power-to	-heat	**CHP**	BP *	conv. fuels, biomass	power & heat	✔	✔ / -	✔	✔ & ✘	✔ / ● / ✘ & ✔ / ✔ / ●	✘	✔ & ●	(✘)	✔
			EC **	conv. fuels, biomass	power & heat	✔	✔ / -	✔	✔ & ✘	✔ / ● / ✘ & ✔ / ✔ / ●	✘	✔ & ●	(✘)	✔
			GT w/ HRB*	gas, biogas	power & heat	✔	✔ / -	✔	✔ & ✘	✔ / ● / ✘ & ✔ / ✔ / ●	(✘)	✔ & ●	(✘)	✔
			CC-CHP*	gas, biogas	power & heat	✔	✔ / -	✔	✔ & ✘	✔ / ● / ✘ & ✔ / ✔ / ●	(✘)	✔ & ●	(✘)	✔
			CU*,**	gas, biogas, liquid fuels	power & heat	✔	✔ / -	✔	✔ & ✘	✔ / ● / ✘ & ✔ / ✔ / ●	✘	✔ & ●	(✘)	✔
			FC *,**	unconv. fuels	power & heat	✔	✔ / -	✘	✔ & ✘	✔ / ● / ✘ & ✔ / ✔ / ●	(✘)	✔ & ●	●	●
			μ-CHP**	gas, biogas, liquid fuels	power & heat	✔	✔ / -	✔	✔ & ✘	✔ / ● / ✘ & ✔ / ✔ / ●	✘	✔ & ●	(✘)	●
		P2H	EB*,**	power	heat	✔	✔ / -	✔	✘	✔ / ✔ / ●*,✘**	(✔)	●	✔	✔
			EHP*,**	power	heat	✔	✔ / -	●	✘	✔ / ✔ /●*, ✘**	(✔)	●	✔	✔
		Hy2H	G&EB**	gas ⊕ power	heat	✔	- / ✔	✔	✘	✔ / ✔ / ✘**	✔	●	●	✔
	-mobility	**P2V**	BEV, PHEV	power	optional propulsion	✔	- / ✔	●	-	✔ / ● / ✘	✔	●	●	✘
		-V2P		stored power for optional propulsion	power	(✔)	- / ✔	●	-	✔ / ● / ✘	✔	✔	●	✘
	-gas	**P2G**	P-to-H_2	power	H_2	●	- / ✔	✘	✘	✔ / (✔) / ✘	(✔)	(✔)	✔	✘
			H_2-to-CH_4	H_2, CO_2	CH_4, (heat)	(✘)	- / ✔	✘	✔	✔ / ✔ / ✔	✘	✔	✔	✘
			H_2-to-CH_3OH	H_2, CO_2	CH_3OH, (heat)	(✘)	- / ✔	✘	●	✔ / ✔ / ✔	✘	●	✔	✘
			H_2-to-syngas	H_2, CO_2	syngas	(✘)	✔ / -	✘	✘	✔ / ● / ✘	✘	●	✔	✘
		G2H	GB *,**	art. gas	heat	✘	- / ✔	✔	✘	✔ / ✔ / ●*, ✘**	✘	●	✔	✘
			GEHP*,**	art. gas	heat	✘	- / ✔	✘	✘	✔ / ✔ /●*, ✘**	✘	●	✔	✘
		G2P	any gas-fueled conv. el. generation techn.	art. gas	power	✘	- / ✔	✔	✔	✔ / ● / ✘	●	✔	✔	✘
		G2CHP	any gas-fueled CHP techn.	art. gas	power & heat	(✘)	- / ✔	✔	✔ & ✘	✔ / ● / ✘ & ✔ / ✔ / ●	✘	✔ & ●	✔	(✘)
	-chemicals P2C		see P2G techn.	power	raw materials	✘	✔ / -	✘	●	✔ / ✔ / ●	-	●	✔	✘

✔: very good/very high/yes, (✔): good/high/partly, ●: medium, (✘): bad/low/barely, ✘: very bad/very low/no
* for district heating (DH), ** for individual heating (IH)
art. gas: artificial gas (any product from P2G apart from syngas, i.e. hydrogen (H_2), methane (CH_4) or mixes), BEV: battery electric vehicle, BP: back-pressure steam turbine, CHP: combined heat and power, CC-CHP: combined-cycle-CHP, CU: cogeneration unit, EB: electric/ electrode boiler, EHP: electric heat pump, EC: extraction-condensation steam turbine, FC: fuel cell, GB: gas boiler, G&EB: gas & electric boiler, GT w/ HRB: gas turbine with heat recovery boiler, PHEV: plug-in hybrid electric vehicle

Source: Own depiction.

basic raw materials[6] (primary products), such as hydrogen or others. In order to avoid further conversion losses due to an energetic utilization of these materials, the bound energy is not supposed to re-enter the energy system in this concept. Instead, these materials serve as primary products for the chemical industry and are commercialized for various other purposes.

Table 1.1 summarizes the various sector coupling technologies and provides a qualitative juxtaposition of several features. It lists the possible technologies with the various input and output combinations and gives a comparative rating ranging from very good, ✔, and good, (✔) to medium, ●, bad, (✘), and very bad, ✘. The features compared are as follows: conversion efficiency, technology maturity, the conversion output's transportability, its storability with regard to short-, medium- and long-term, its usability/applicability, the technology's ability as ancillary service or means of flexibility provision, its ability to assist in substitution of primary energy carriers and the same for system cost optimization. Additionally, the various sector coupling technologies are classified of being either uni- or bi-directional.

This thesis focuses on sector coupling in the form of power-to-heat and combined heat and power. Unlike other forms of sector coupling, these technologies are already mature and have advantageous conversion efficiencies compared to power-to-gas. Hence, their market deployment is already ongoing; in the case of CHP, for many decades, and market deployment of power-to-heat is currently taking place. Due to its lower technical and economic efficiency, the employment of power-to-gas is therefore considered here rather as a technology of last resort to cope with RES power surpluses or as a means toward decarbonization of the energy sector farther in the future. In this thesis, power-to-gas appears only circumstantially as a storage alternative. The large-scale deployment of technologies with electric power for mobility depends largely on technical developments of electric vehicles, alternative propulsion technologies, their infrastructure, and acceptance by consumers. In order to keep to a well-structured scope of this thesis, power-to-vehicle-to-power and all its intricacies are left for further research elsewhere.

1.4 Overview of the thesis

Sections 1.1 and 1.2 highlight the motivation and research questions pursued in this thesis, respectively. Chapters 2 to 5 each consist of one original research article. Each article seeks to answer these research questions by presenting the employed methodology, the data, and the results.

1.4.1 Publications and contributions

Table 1.2 provides an overview of the four main chapters, the author's contributions to the four research articles, and their publication status. The article contained in Chapter 2 *Power-to-heat for renewable energy integration* (Bloess, Schill, and Zerrahn, 2018) is a

[6] power-to-chemicals is also often referred to as power-to-materials, same as P2C (P2M).

Table 1.2: Contributions and publications of the articles contained in Chapters 2 to 5.

	Chapter 2:	**Chapter 3:**	**Chapter 4:**	**Chapter 5:**
	Power-to-heat for renewable energy integration ... Bloess, Schill, and Zerrahn (2018)	*Modeling of combined heat and power generation ...* Bloess (2020)	*Impacts of heat sector transformation ...* Bloess (2019a)	*Urban energy transition ...* Bloess (2019c)
authors	Andreas Bloess, Wolf-Peter Schill, Alexander Zerrahn	Andreas Bloess	Andreas Bloess	Andreas Bloess
contributions	Responsibility for large parts of literature search and literature systematization in Tables 2.1, 2.2 and 2.4, as well as for Sections 2.5 and 2.6.	Independent research by the author.	Independent research by the author.	Independent research by the author.
publications	Published in *Applied Energy*, 212 (2018), p. 1611–1626.	Published in *Applied Energy*, 267 (2020), p. 114727.	Published in *Applied Energy*, 239 (2019), p. 560–580.	Submitted for peer reviewing and publication in *Applied Energy.*
DOI	https://doi.org/10.1016/j.apenergy.2017.12.073	https://doi.org/10.1016/j.apenergy.2020.114727	https://doi.org/10.1016/j.apenergy.2019.01.101	
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joint endeavor by the author and two colleagues from the German Institute for Economic Research (DIW Berlin). As the title indicates, the article comprises a literature review on power-to-heat in energy system modeling, and was published in the peer-reviewed international journal *Applied Energy.* The author of this thesis was mainly responsible for seeking out and systematizing a large part of the literature reviewed in the Tables 2.1, 2.2, and 2.4 and the writing of Sections 2.5 and 2.6. The Chapters 3, 4, and 5 are modeling exercises all focusing on power and heat sector coupling. They are all entirely realized by the author of this thesis. The article *Modeling of combined heat and power generation in the context of increasing renewable energy penetration* (Bloess, 2020) contained in Chapter 3 is a stylized energy system analysis emphasizing the operation of CHP and power-to-heat and has been published in the international journal *Applied Energy.* In contrast, the other two articles are

future case studies on the transformation of real world energy systems. Chapter 4's article *Impacts of heat sector transformation on Germany's power system through increased use of power-to-heat* (Bloess, 2019a) analyses the joint power and heat supplies for Germany up to 2050 subjected to an increasingly tightening CO_2 emissions constraint. Germany's power supply is embedded in the European power system. The low temperature heat supply for space heating and domestic hot water is divided into individual heating and district heating. This work has also been published in the journal *Applied Energy*. Chapter 5's article *Urban energy transition: The impact of increasing renewable energy sources on the Berlin power and heat energy systems* (Bloess, 2019c) has been submitted for publication at *Applied Energy* and looks in particular at the Berlin energy policy concerning the joint urban power and district heating supplies with a power supply embedded in the German national power system.

1.4.2 Methodological comparison

Table 1.3 provides an overview of the different model features applied in the model-based analysis of Chapters 3, 4, and 5. Since Chapter 2 is a pure literature review, its methodological approach is not comparable. In the article assigned to Chapter 2, the search field was limited to leading international peer-reviewed journals of applied and economic energy research and published before January 1st 2017 in the Web of Science Database. The journals were screened for keywords in connection with power-to-heat. Furthermore, among those retrieved articles, a forward and backward search was conducted in order to locate papers cited in the articles and to find where they are being cited themselves. Finally, 46 articles were identified with a narrow focus on techno-economic model-based assessments of residential power-to-heat in the context of variable electric RES integration. These articles were systematized into three tables summarizing the facts concerning the papers' research scope in Table 2.1, the research methods employed in Table 2.2, as well as the set research objective and focus in Table 2.4.

Table 1.3: Overview of model features.

	Chapter 2:	**Chapter 3:**	**Chapter 4:**	**Chapter 5:**
	Power-to-heat for renewable energy integration ...	*Modeling of combined heat and power generation ...*	*Impacts of heat sector transformation ...*	*Urban energy transition ...*
	Bloess, Schill, and Zerrahn (2018)	Bloess (2020)	Bloess (2019a)	Bloess (2019c)
areas covered	various	stylized joint power and district heating system	Germany embedded in Europe	Berlin embedded in Germany

Continued on next page

Table 1.3 – *Continued from previous page*

	Chapter 2:	**Chapter 3:**	**Chapter 4:**	**Chapter 5:**
type of model	no own model development	partial equilibrium model (LP)	partial equilibrium model (LP)	partial equilibrium model (MILP)
objective function	–	cost minimization	cost minimization	cost minimization
decision variables	–	investment and dispatch	investment, decommissioning and dispatch in Europe	investment, decommissioning and dispatch in Germany and Berlin separately
endogenous investments	–	power and heat generation	power generation in Europe, heat generation in Germany additionally, transmission between countries	power generation in Germany and power and heat generation in Berlin
driving constraints	–	tightening CO_2 emissions cap	maximum yearly CO_2 emissions	minimum share of RES power generation and maximum yearly CO_2 emissions
time horizon	–	static, one year	dynamic, long-term until 2050	static, long-term until 2050
temporal resolution	–	hourly	hourly	hourly
intertemporal features	–	ramping, power and heat storage	ramping, power and heat storage	ramping, power and heat storage, heat accumulation in DH piping
reference year	–	2015	2015	2015
modeled energy sources	–	hard coal, gas, solar, wind	nuclear, lignite, hard coal, oil, gas, biomass, hydro, solar, wind	lignite, hard coal, oil, gas, biomass, solar, wind
modeled generation technologies	–	ST, CC, GT, CHP, PV, WT, DHB, DHEB, GSHP	ST, CC, GT, CHP, HT, PV, WT, GB, EB, HP	CC, GT, CHP, PV, WT, DHB, DHEB, GSHP, S2H, RHB, REB

Continued on next page

Table 1.3 – *Continued from previous page*

	Chapter 2:	**Chapter 3:**	**Chapter 4:**	**Chapter 5:**
modeled storage technologies	–	batteries, P2G, TES	PSP, DSM, batteries, P2G, TES	batteries, P2G, TES
energy transmission representation	–	–	power transmission among countries	heat transmission network
implementation	–	GAMS	GAMS	GAMS
solver	–	CPLEX	CPLEX	GUROBI

In Chapter 3, a simple linear partial equilibrium cost-minimizing investment and dispatch model is employed to cover hourly power and heat loads. In order to analyze the performance of various CHP technologies individually in terms of total fuel efficiency and full load hours, the same power and heat loads as well as the same capacity factors for vRES are applied in six stylized energy systems. By providing the model with only a single CHP type, and, for juxtaposition with uncoupled generation, only a single conventional power-only generation technology in combination with a gas-fueled heat boiler, each system allows for the examination of the respective CHP technology separately. The sixth energy systems permits a free choice from all CHP and conventional power and heat-only generation technologies. The CHP types under investigation are back-pressure steam turbines (BPs), extraction-condensation steam turbines (ECs), combined-cycle extraction-condensation CHPs (CCECs), and gas turbine CHPs (GTCHPs). Table 3.3 provides an overview about the six energy systems and their respective set of technologies. The capacities for CHP and uncoupled conventional power and heat generation are determined endogenously at 0% vRES penetration. These capacities are fixed thereafter and the vRES penetration is increased in each system in ten percentage points from 0% to 100% by means of an increasingly tightening CO_2 emissions constraint. This illustrates the development of power and heat generation as well as investments into other technologies, such as power-to-heat, power and heat storage, and power-to-gas, under increased vRES penetration of the system.

The partial equilibrium model applied in the article contained in Chapter 4 is based on a pre-existing power-only system model named dynELMOD, which was developed by Gerbaulet and Lorenz (2017). It is a techno-economic linear program (LP) cost-minimization model that dynamically covers the operation and investment problems of 33 European countries over a long-term time horizon up to 2050. Under a CO_2 emissions constraint that tightens on a yearly basis for each country, the model endogenously determines decommissions of existing power plants and investments into new capacities for power generation, storage, and transmission between countries. Furthermore, it endogenously optimizes the short-term operation of capacities under the constraint to hourly balance power load

and generation. The model is extended to dynELMOD+heat in this work to cover the German individual and district heating demand for space heating and domestic hot water. Thus, heat generation investments for both are endogenously determined to balance hourly heat loads as well. The model extension enables investment and operation decisions covering CHP and heat-only plants for district heating and conventional condensation boilers, cogeneration units, and solar-thermal capacities for individual heating. In both areas, various power-to-heat capacities and heat storage can also be invested in and operated. Using this extended model, five scenarios are examined and juxtaposed. The Power System-only (PS-only) scenario, which omits the heating demand, is congruent with the reference case of the original dynELMOD model. Moreover, there is a Decreasing Heat Demand (DHD) and a Constant Heat Demand (CHD) scenario. In the former, it is assumed that heat demand decreases by 2050 according to the political targets set by the German federal government as a result of the successful realization of energy efficiency measures, beneficial consumer behavior adjustments, and other heat energy consumption reductions. The latter scenario, however, takes a pessimistic view, in which no heat energy consumption reductions are achieved. Additionally, both scenarios are varied without power-to-heat technology available (DHD w/o P2H and CHD w/o P2H). An overview and the crucial assumptions inherent to the five scenarios are listed in Tables 4.1 and 4.2, respectively.

The analysis of Berlin's joint power and district heating system found in Chapter 5 requires the consideration of the national German power system as a whole, as the Berlin energy system is an integral part of that larger system and imports half of its consumed electricity from the national power grid. Moreover, increasing capacities of RES used to generate electricity in the national power system heavily affect conventional power and CHP generation in Berlin. Therefore, the investment and dispatch cost optimization model of this analysis balances power in both the German power system and in the Berlin power system. For the German power balance, the model endogenously determines optimal capacity decommission and investment decisions under the constraint of minimum shares for RES in the power system. These shares correspond to the historical share of 29% in 2015 and to national energy policy targets for the years 2020, 2030, and 2050, with shares of 35%, 50%, and 80%, respectively. Simultaneously the model balances the Berlin power and heat loads under additional CO_2 emissions constraints according to the scenarios under investigation. To cover heat loads in the district heating system, the available set of technologies for Berlin comprises additional heat technologies such as various CHP types, power-to-heat, solar-to-heat (S2H), and thermal energy storage. The two power balances in the model are connected to the extent that Berlin can freely import power at the actual shadow prices and CO_2 intensities in the national power system. In this regard, Berlin is assumed to be a price taker. This work compares the Reference scenario for Berlin for the year 2015, the BECP scenario with an increasingly tightening CO_2 emissions constraint over the years 2020, 2030, and 2050, and the business-as-usual scenario over the same years without CO_2 emissions constraint. A special feature of this model is the stylized heat transmission network as depicted in Figure 5.5, representing the Berlin district heating network. It allows the modeling of the course of heat energy flows with endogenously determined cascading temperature levels from a central heat supply station to the point of district heating con-

sumption and back. This feature enables, first, the incorporation of heat transmissions losses of supply and return heat energy flows depending on ambient and network temperature; second, the partial or complete shift of heat generation to the consumption site by means of gas-fueled residential heat boilers (RHBs) and residential electric boilers (REBs), which potentially avoids costs of running the district heating network; third, the modeling of heat storage effects by accumulating heat within the network piping; forth, to impose realistic and dynamic thermal limits in the operation of TES tanks, large-scale GSHPs, and solar-to-heat; and, fifth, the examination of the effects on investment and operation of these technologies when the maximum supply and return temperature are exogenously lowered. Concerning the latter, six hypothetical technical transformations of the district heating network are additionally examined. This leads to a total of $1+2\cdot3\cdot6=37$ simulations for Berlin's joint power and district heating system. The special features of the heat transmission network modeling required the model to be formulated with mixed-integer linear program (MILP). A scenario overview and their parameter variations is given in Table 5.1.

1.5 Conclusions

1.5.1 Power-to-heat for renewable energy integration

The literature review on renewable energy integration by means of power-to-heat revealed a very diverse range of analyses. Most are techno-economic partial equilibrium models of the energy sector simulating the optimal dispatch of a joint power and heat supply. Only a minority of papers involved also address the investment optimization problem. The significantly higher occurrence of research with geographical scopes in northern and western Europe is striking. All of the countries within these scopes have ambitious policies concerning long-term decarbonization in place and many base these policies on non-dispatchable RES, like PV and wind power. In particular, papers from Denmark emphasize the role of district heating networks. There are only few papers with cases from North America. Thus, complementary insights from Asia, the Americas and Africa would be of value, especially when power and heat infrastructures are less developed compared to most European cases as analyzed here. In order to examine energy system penetrations with high shares of non-dispatchable RES, such as 40-60% or higher, all the studies employ long-term time horizons up to 2030 or 2050. Table 2.1 provides a summary concerning the research scope. However, not all analyses explicitly specify the degree of penetration with RES or the renewable technology. Furthermore, the papers differ greatly regarding the level of technological detail. Whereas some present very unique and inventive formulations, for instance, for heat pumps or passive heat storage, others present technologies in a stylized way, if formulations are shown at all. Unlike heat pumps, electric/ electrode boilers (EBs), or heat storage, hybrid heating technologies and smart electric thermal storage (SETS) are barely taken into account. Some authors also include sector coupling with other end-use energy sectors, such as the mobility or cooling sector. Yet, since the focus of this review is only on power-to-heat, no judgment on this wider field of research shall be given here. In

summary, the reviewed literature shows a great variety of how to couple power and heat supplies with the various power-to-heat technologies available in order to integrate variable renewable electricity and to decarbonize the heat supply. Due to the different geographical contexts, time horizons and assumptions on costs, policies, and technology availability, the numerical findings are generally very idiosyncratic. Nevertheless, there are also some common findings that may be highlighted.

In terms of methodologies applied, the majority of reviewed articles consist of optimization exercises that apply cost minimization and assume perfect competition and foresight among market actors within an equilibrium state. Alternative objectives correspond to welfare maximization or minimization of residual load variability. Many models are long-standing modeling projects originating from electricity only systems that evolve to joint power and heat system analysis. More prominent and more often applied models in various case studies are notably BALMOREL, TIMES, and energyPLAN. Whereas the two former models employ cost minimization, the latter minimizes fossil fuel use. Most models are LPs or MILPs formulations. Yet, integer variables are rather used for greater realism in pure dispatch models. Only very few apply them for investment decision problems as well, for which LP approaches are computationally more convenient. Whereas most models had an hourly time resolution, they also all reduced the number of time slices by some time aggregation method. This turns out to be especially the case when integer variables are combined with endogenous investment decisions. Models with sub-hourly resolution are definitely the exception. An alternative approach to analytical optimization has been identified by heuristic methods, where technologies are dispatched according to an a priori determined hierarchy in case of negative or positive residual load; for instance, in case of renewable surpluses the priority list is storage charging, fuel replacement in industry by power-to-heat instead of fuel-to-heat and finally hydrogen production. In the opposite case of shortage, storage discharging comes first, followed by imports, dispatchable generation adjustments, and finally, load shedding.

Noteworthy modeling approaches have been identified for heat pumps, active heat storage and passive heat storage in building mass. Concerning heat pumps, some simplifications compared to more complex real world understanding of the functioning seem to be common in the energy system modeling community. A common practice is to assume a constant average coefficient of performance for electric heat pumps. Furthermore, it is common to apply exogenously determined hourly coefficient of performances, depending on the heat source and sink temperature level or COP functions derived from empirical data. All these approaches treat the problem in a linear way in order to avoid actual non-linear relations, since a heat pump also influences its heat sink's temperature level. Moreover, there are several practices of combining heat pumps in modeling with electric peak load boilers, which saves investment costs in the capacity design. Active heat storage is found to be modeled most often with a standard approach as is also typical for power-to-power storage modeling. Only some variations concerning static and dynamic losses are observable. More noteworthy and significant is the differentiation in the modeling of large-scale central heat storage as used for district heating and small-scale decentralized heat storage for individual heating. In the former, modelers emphasize the charging and discharging constraints and

negligible static losses, whereas in the latter, unconstrained charging and discharging in the short term with considerable static losses are highlighted. Only a single paper has been found that addresses the topic of heat accumulation in the piping of district heating networks. A few studies have been identified that contain elaborate formulations concerning passive heat storage within the building mass or by allowing tenable positive or negative deviations from a reference temperature for space heating. In all heat storage modeling, it was common to assume perfect foresight in the storage operation. An overview of the methodological findings is to be found in the Table 2.2.

Furthermore, all reviewed works do not just differ in terms of research scope and methodologies, but also in their research objective. The three major motivations and objectives of research identified for residential power-to-heat are its potential for system integration of variable RES, its contribution to decarbonization of the energy sector and its cost-effectiveness. Since these three aspects influence each other, it is difficult to disentangle them, but the focus varies. Moreover, some analyses include research on additional electricity demand due to power-to-heat, the structure of heat supply, its impact on power prices and some emphasized on methodological contributions by presenting model formulations or particular model features. Table 2.4 provides an overview on which articles mainly pursued which research objectives.

Synthesizing the insights from all works reviewed power-to-heat is commonly found to be a cost-effective means for variable RES integration, due to five major cost reduction drivers: (i) the substitution of fossil fuels; (ii) improved use of capital invested into vRES assets thanks to reduced curtailment; (iii) reduced need for other costly auxiliary technologies; (iv) improved and more efficient operation of conventional power plants based on the lesser occurrence of cycling and part-load operation; and (v) the exploitation of synergies of existing district heating infrastructure. In particular, the combination of heat pumps and passive heat storage in the residential sector are accentuated by several authors as a low-cost option for reducing curtailment of vRES. Active heat storage, in contrast, would incur relatively high investment costs and energy losses that would lead to only minor (if any) decreases in overall system costs. Thus, it is advisable for future research in joint power and heat energy systems to incorporate passive heat storage modeling. Additionally, some authors point to the general transformation away from fuel costs toward investment costs in energy systems with considerable shares of RES and power-to-heat, and contending that such systems incur only slightly higher total costs for substantially lower emissions compared to more fossil-based scenarios. Comparing to other sector coupling options, power-to-heat is favored as the most cost-effective coupling. Coupling the power and hydrogen sector could lead to similar costs as achieved through savings related to fuel consumption; however, higher investment costs would also arise. Electrolysis could also provide more flexibility than heat pumps, but this is offset by lower efficiency and is thus, uneconomical. Furthermore, power-to-heat is also considered to be more cost-effective than the grid integration of battery electric vehicles. Yet, an adequate mix of the two options leads certainly to even higher cost-effectiveness.

Power-to-heat as a means for better variable RES integration can be understood in two ways. First, it can increase the utilization of existing capacities, thereby reducing

variable RES curtailment and, second, it allows for the utilization of even greater capacity expansions of the variable RES. This improved integration is enabled by making better use of temporary renewable surplus generation through three major mechanisms: (i) electric heating without additional heat storage particularly in district heating; (ii) by employing additional active or passive heat storage chargeable with power-to-heat; and (iii) by flexible fuel switching in hybrid heating systems enabling virtual energy storage.

As a consequence, any MWh of electric RES that can be integrated further into the system through power-to-heat, can also substitute more than one MWh of fossil primary energy for heating, leading to a respective savings of CO_2 emissions and, thus, to decarbonization. Several papers reviewed present *ceteris paribus* analyses comparing optimal system configuration with and without power-to-heat technologies to measure its decarbonization potential. Nevertheless, the results are highly dependent on the applied context; in summary, they are substantial in most cases with relative emissions savings in a two-digit range at minimum.

Moreover, the impact of power-to-heat on overall power demand and power prices is investigated in several studies. Substituting other fuels for residential heating with electricity certainly increases electricity demand and its power prices. Yet, the high efficiency of heat pumps and their beneficial flexibility can counteract this effect to some extent. The common tenor in the reviewed works is that power-to-heat has a strong impact on peak loads and hence, on power prices, when it is inflexible. However, the passive or active heat storage render power-to-heat more flexible and significantly relax peak load power prices.

Concerning the development of the structure of heat supply, that is, the annual dispatch of various residential heating technologies, many research articles conclude heat pumps will become the dominant technology from 2030 to 2050, often backed up by electric resistive heaters. Especially in individual heating, most authors see a decline in the use of natural gas and oil. Whereas the latter is phased-out earlier, the former still maintains a smaller role until 2050. In terms of district heating, the views are more diverse: Whereas there seems to be consensus that district heating networks will continue to play an important role by 2050, it appears rather controversial to which extent they will employ power-to-heat. Others also see here an optimal operation mix of large-scale heat pumps and CHP plants. Only one research project reflected skepticism regarding the development of heat pumps and concludes that, in Germany, natural gas will retain its leading market position due to prevailing market and institutional inertia.

1.5.2 Modeling of combined heat and power generation

Combined heat and power (CHP), also referred to as cogeneration, can achieve very high fuel efficiencies of up to 90%. This advantage is usually highlighted in comparison to the uncoupled generation of power and heat. Therefore, many countries' energy policy, including Germany's, considers CHP as generally economical and ecologically sound at meeting power and heat demands and to assists in simultaneously reducing primary energy consumption and greenhouse gas emissions.

As bivalent energy generators, CHP plants represent a power and heat sector coupling

technology that injects electricity into over-regional power grids and supplies heat either directly to industrial production or indirectly to residential consumers by means of a district heating network. Unlike power, heat cannot be transported over long distances without considerable transmission losses and must therefore be consumed locally. Consequently, CHP plants face additional constraints compared to conventional power plants. In order to make use of the waste heat involved in power generation, they require a heat sink to be in its vicinity and, being obliged to respond to its demand, the plants' flexibility is more constrained than conventional power generators. With the increasing integration of variable renewable energy sources, the growing need for flexibility in the power system, and the rise of alternative heat technologies, like power-to-heat, the role of CHP and its contributions to a future energy system become controversial and unclear.

In order to analyze the performance of various CHP technologies individually in future energy systems, the work contained in Chapter 3 provides an appropriate modeling technique and parametrization for the various types of CHP plants. Furthermore, it demonstrates theoretically in Figure 3.3 the high fuel efficiency's dependence of CHP technology on the power share within the power and heat output combination. According to that figure, CHP achieves higher fuel efficiencies than an uncoupled power and heat generation only within certain ranges of power shares when juxtaposed with today's highly efficient uncoupled power and heat generation technologies based on gas. Comparing CHP technologies with two degrees of freedom, CCEC plants always achieve a higher fuel efficiency than EC or GTCHP plants when the power share is high. When the power share decreases, GTCHP show a higher fuel efficiency at some point; when it decreases even further, uncoupled power and heat generation by CC plants and district heating boilers (DHBs) can be even more efficient.

Assuming that CHP plants cover only residual power load, increasing vRES penetration can have a strong impact on the power share within the power and heat output combination. On the one hand, RES for electricity decrease the power share, whereas on the other hand, alternative heating technologies to CHP increase the power share. The analysis in Section 3.2.4 suggests that at very low power shares, CHP plants can maintain their high fuel efficiency only at the expense of generally lower output levels, which means a decrease in full load hours. Uncoupled technology combinations can represent any power share within the power and heat output combination without each technology's efficiency being affected. In this context of increasing vRES, the separate techno-economic analysis of the various CHP types in combination with uncoupled power and heat generation technologies as an alternative within six stylized energy systems, permits the examination of each CHP technology's interaction with other technologies and performance in terms of fuel efficiency and full load hours individually.

According to the analysis, back-pressure steam turbines can be dimensioned to cover only a small share of maximum power and heat load. The strictly coupled power-over-heat-ratio of this type of CHP plant imposes too little flexibility to contribute to larger parts of power and heat generation and must therefore be accompanied by respectively large capacities for uncoupled generation. This type of CHP has a very high fuel efficiency of 90% that is not affected by increasing vRES penetration. Nevertheless, this advantage

can be barely exploited in the system and with the increase of vRES penetration, full load hours decrease as well.

In contrast, an extraction-condensation steam turbine can be dimensioned significantly larger in the same energy system. Since it can partly or fully operate like a conventional power plant, it requires less supplemental capacity by uncoupled generation. Although not all of its power output is necessarily cogenerated, it covers most of the residual power load, given that a conventional steam turbine is the alternative. With increasing vRES penetration, the EC plants run even more often on the back-pressure line leading to a higher average fuel efficiency, which is mostly 13 to eight percentage points below the possible maximum (75%). The electrical efficiency decreases accordingly and is consistently about five percentage points below the possible maximum (40%). Since operation points also concentrate more on lower output levels on the back-pressure line, this corresponds to a decrease in full load hours with increasing vRES penetration.

When comparing the back-pressure steam turbine and the extraction-condensation steam turbine to uncoupled power and heat generation via a combined-cycle gas turbine and a heat boiler, the uncoupled power generation always proves to be advantageous. Already at low vRES penetrations, both CHP types become idle, since the uncoupled power and heat generation technologies provide a higher electrical and thermal efficiency, respectively. Even in situations of high residual power and high heat loads, the available CHP plants are not operated.

The only CHP technologies that can compete with the uncoupled alternative of a combined-cycle gas turbine and a heat boiler are CCEC and GTCHP plants. Examining the CCEC plant individually here, like the EC plant, fuel efficiency increases with increasing vRES penetration, which is offset by a decrease in full load hours. In fact, the plant operates more often on the back-pressure with 75% fuel efficiency, but with lower power and heat output levels. Compared to the combined-cycle gas turbine, the electrical efficiency of the combined-cycle extraction-condensation CHP is consistently five to six percentage points below 52%.

When the choice of technology is left open to the model, most investments go into gas turbine CHP capacity and some into capacities for combined-cycle gas turbines and combined-cycle extraction-condensation CHPs. The GTCHP proves to be most apt at running closely to its maximum fuel efficiency of 85% and to its maximum electrical efficiency of 35% at low or high vRES penetration. Nevertheless, with increasing vRES, its contributions to the coverage of residual power demand and, thus, full load hours, decrease substantially faster than those of the combined-cycle gas turbine and combined-cycle extraction-condensation CHP.

In summary, as vRES penetration increases, fuel efficiency of all CHP technologies with two degrees of freedom actually increases. Nevertheless, this higher fuel efficiency is offset by decreased full load hours. Even at very high vRES penetrations of 90% or higher, when CHP technology can be fueled by synthetic gas produced by power-to-gas, CHP technology no longer plays a role. The share of CHP power generation in the residual power generation actually increases due to a more efficient operation, yet, its share in the heat generation decreases, as it is substituted by power-to-heat technologies like ground source heat pumps

and electric/ electrode boilers.

1.5.3 Impacts of heat sector transformation

While keeping in mind its contributions to total final energy consumption and greenhouse gas emissions in Germany, lower importance should not be attributed to heating supply than to the power sector within a comprehensive energy transformation policy. Biomass as a zero CO_2 emissions fuel is expected to provide only a very restricted potential to decarbonize the heating supply. This is due to the fact that its availability is limited and its use for low temperature heating is in competition with other heat applications of higher temperature levels. Thus, electricity based on RES used in various power-to-heat technologies is assumed to play a key role in this transformation. Moreover, the interactions between the power and heat sectors through the increased use of sector coupling technologies, such as power-to-heat and CHP, help to integrate RES in both sectors. In particular, when dealing with short-term variations in the occurrence of wind and solar power, power-to-heat provides additional flexibility to conventional flexibility measures, such as transmission expansion or power-to-power storage.

The novel analysis of the German individual and district heating demand by means of the extension of the dynamic long-term European electricity system model, dynELMOD+heat, reveals important implications for the German power system. In the scenarios involving power-to-heat, electricity becomes an increasingly important energy carrier for residential heating. In the optimistic Decreasing Heat Demand (DHD) scenario, substantial reductions in heat energy consumption are assumed to take place up to 2050; in contrast, in the pessimistic Constant Heat Demand (CHD) scenario, these reductions are not assumed to take place at all. In both scenarios, power-to-heat dominates district heating from 2030 on and substitutes nearly all other alternatives up to 2050. The emphasis here is clearly on ground source heat pumps with some additional electrode boiler capacity, with the only differences being that the capacity expansion in the CHD scenario is a multiple of that in the DHD scenario and also with much greater share in ground source heat pumps. Indeed, such domination of power-to-heat in district heating could lead to abolishing district heating networks due to relatively high heat transmission losses compared to power distribution losses. Nevertheless, technical progress, economies of scale in accessing ground source heat energy, and alternative heat sources, such as waste incineration or industrial waste heat, can still justify the maintenance of district heating infrastructure. Only in the scenario variations, in which power-to-heat technology is suppressed (DHD w/o P2H and CHD w/o P2H), coal-fueled heating in back-pressure CHP plants experiences a revival in 2040 and is phased out and replaced shortly after in 2050 by gas-fueled heat-only plants, because the tight emissions constraint in the final year enforces a low emissions fuel switch and the requirement of very flexible technology.

However, due to its substantially greater size, the main driver for increased electricity demand comes from power-to-heat in individual heating. In the optimistic as well as in the pessimistic heat demand development scenario, power-to-heat dominates the heating supply in 2030 and covers its demand completely in 2040 and 2050. This happens even

though there is no emissions constraint employed in the individual heating supply. This endogenous transformation to 100% heating from power-to-heat is explained through the reduced curtailment of RES, lower expenditures for costly flexibility alternatives, like storage or DSM, and decreasing costs for wind power and PV. In the DHD scenario, the installed capacity for power-to-heat mainly consists of air source heat pumps with some electric boiler capacity. In the CHD scenario, however, ground source heat pumps are significantly emphasized. Thus, their higher investment costs are only justified by a certain total quantity of heat generation. The scenario computations without power-to-heat show a greater mix of oil, gas, and biomass-fueled heating. Investment into solar-thermal heating cannot be shown.

In total, this increased use of power-to-heat in Germany necessarily causes a substantial rise in additional electric power demand. According to the underlying assumptions, Germany's yearly conventional net electric energy demand will rise from 540 $\mathrm{TWh_{el}}$ in 2015 to a peak above 610 $\mathrm{TWh_{el}}$ in 2030 before continuously decreasing until 2050. In the DHD scenario, the endogenously determined additional electric energy demand caused by power-to-heat will also peak with more than 200 $\mathrm{TWh_{el}}$ in 2030 and will decrease to nearly 110 $\mathrm{TWh_{el}}$ in 2050 thanks to lower space heating demand and technical progress in heat pumps. With more than 90% this extra consumption is mainly driven by individual heating. In the CHD scenario the additional electric energy demand increases sharply to over 260 $\mathrm{TWh_{el}}$ in 2040 and remains there stable. The DHD scenario's increase to 110 $\mathrm{TWh_{el}}$ in the long run is in line with other studies of Germany. The increase shown by the conservative CHD scenario shows an upper bound for extra power demand that is two and a half times as high as in those studies that allege substantial heat consumption reductions.

Such magnitude of extra electric energy demand in Germany obviously bears an impact on the power supply side development. Yet, the power generation capacity is not just evenly expanded compared to computations without power-to-heat. The varying demand profile of space heating also causes shifting on the supply side's optimal technology mix; for instance, wind power expansion is strongly affected. Compared to the expansion to 130 $\mathrm{GW_{el}}$ in 2050, in the Power System-only scenario, this amount will already be surpassed in 2030 in the DHD and CHD scenarios reaching in 2050 nearly 160 $\mathrm{GW_{el}}$ and 165 $\mathrm{GW_{el}}$, respectively. In contrast, the development of PV capacity installations is in all scenarios similar with 135 $\mathrm{GW_{el}}$ in 2050. This indicates that power-to-heat has a powerful drive on the expansion of wind power, but not of PV. This can be explained by the fact that the occurrence of space heating demand in winter behaves cyclically with stronger capacity factors for wind power, but anti-cyclically with the capacity factors of PV, which are naturally weaker in winter and stronger in summer.

Furthermore, in the computations with power-to-heat, power generation based on gas also has greater importance than in computations without power-to-heat. Compared to only 40 $\mathrm{GW_{el}}$ in 2050 in the Power System-only scenario, the DHD and CHD scenarios show expansions of up to 130 $\mathrm{GW_{el}}$ and 135 $\mathrm{GW_{el}}$, respectively, consisting of combined-cycle and open-cycle gas turbine plants. Among fossil energy carriers, gas becomes most important; yet, compared to wind power, its contribution to power generation is minor in the future. Very low capacity factors indicate its role as a backup and peak-load capacity.

Moreover, it is noteworthy that this expansion development is dominated only by conventional power plants, whereas there are barely investments into CHP technology. In times of low availability of electric RES, the computations choose the technology combination of highly efficient combined-cycle gas turbine plants and heat pumps as an alternative. This technology mix has a significantly higher flexibility and efficiency compared to CHP. Hence, results do not indicate a future for CHP technology.

The analysis of differences in the sources of Germany's power generation between the DHD and CHD scenarios and the Power System-only scenario reveals that additional generation will come primarily from gas-fueled generation and increases in imports in 2020 in the DHD scenario. Later, important contributions by wind power are added as major source. Due to the tight emissions constraint in 2050, gas-fueled power generation drops heavily. The even greater demand in the CHD scenario is additionally covered by biomass power generation and even larger imports.

Furthermore, there are significant impacts on the requirement for power-to-power storage capacities when there is a substantial power-to-heat deployment. In particular, capacity investments in batteries and power-to-gas storage change compared to results in a power system-only analysis. In the Power System-only scenario, batteries expand to about 35 GW_{el} charging/discharging capacity with 230 GWh_{el} of storage volume by 2050. In the DHD and CHD scenarios, this development is clearly lower with 16 GW_{el} capacity with 84 GWh_{el} storage and 20 GW_{el} capacity with 124 GWh_{el} storage, respectively. Instead, the focus is much higher on power-to-gas storage developing to 50 GW_{el} and 70 GW_{el}, respectively, in the two power-to-heat scenarios by 2050 compared to only 26 GW_{el} in the Power System-only scenario. Whereas batteries have a comparatively high cycle-efficiency, but are costly in purchase, power-to-gas provides zero-cost storage, but with poor conversion efficiency. Consequently, with power-to-heat as a flexibility alternative, the need for frequent storage activities in the short term and thus, the need for battery storage, is significantly reduced. Power surpluses over the conventional power load can be utilized directly for heating. Instead, the low-cost long-term storage of power-to-gas is favored in the overall technology mix. Whether or not the option to invest in power-to-heat is omitted, no significant expansion of heat storage is shown, which can be expected given its substantially lower investment costs compared to power storage. Rather, power-to-heat and conventional heating technologies in individual and district heating might be flexible enough to waive heat storage. Hence, an expected greater role of heat storage opposed to power storage requires further examination.

1.5.4 Urban energy transition

Many countries, including Germany, pursue as part of their overall climate protection and energy policy the large-scale deployment of variable renewable energy source to reduce their CO_2 emissions. Urban areas like the city of Berlin that have a large and well-integrated district heating network can offer important potential to national power systems to integrate power surpluses from vRES. These cities can likewise benefit from integrating these surpluses when they themselves aim to decarbonize their energy system. After Moscow

and Warsaw, Berlin's district heating network is the largest in Europe and among the very largest in the world in terms of piping length and the number of dwellings supplied. Hence, its potential of integrating surpluses from vRES is considerable.

In 2016, Berlin legislative powers passed the energy transition act for Germany's capital city state. By means of the Berlin Energy and Climate Protection Program (BECP), the state government has since pursued additional measures to the already existing national and European policies consisting of the European emission trading system, the strong support of RES, the nuclear phase-out, and the national coal exit. According to this additional state legislation, the city's government is obliged to implement strategies and actions to reduce CO_2 emissions by the city to 60% by 2020, 40% by 2030, and 15% by 2050, compared to the 1990 levels. Throughout these years, national policies will aim at increasing the minimum share of RES for electricity in the German power system to 35%, 50%, and 80%, respectively.

The BECP identifies five fields of action for the city, one of which is Berlin's energy sector. It consists of power and district heating supplies that are currently based mainly on coal and gas for CHP generation and on electricity imports. In order to achieve the city's targets set by politicians, the BECP requires a reduction in energy consumption, an increase in energy efficiency and in the shares of RES, such as PV and wind power, originating from within the boundaries of the city. Moreover, the energy sector should perform a fuel switch away from lignite, coal, and oil toward an emphasized use of gas. This includes a phase-out from lignite, which was executed in 2017 by decommissioning Berlin's only lignite-fueled CHP plant, HKW Klingenberg, and a phase-out from coal energy by the end of 2030. The latter affects the four CHP plants, HKW Moabit A, HKW Reuter C and HKW Reuter West D and E, which account together for 31% of city's power capacity and for 26% of the city's thermal capacity. In particular, the BECP focuses on the role of CHP in the form of modern and flexible combined-cycle extraction-condensation CHPs plants, because of the technology's promised high total fuel efficiency. Berlin's district heating network should be further expanded and densified. It transports heat energy for space heating and domestic hot water heating in the form of pressurized hot water, which reaches currently temperatures of up to 140°C in peak load times. Such high temperature levels render it practically impossible to make use of alternative heating technologies, such as ground source heat pumps or solar-thermal collectors. Therefore, the BECP also addresses the technical transformation of Berlin's district heating network toward lower supply and return temperatures to integrate alternative heat sources. Additional technologies which the BECP intends to employ to achieve its targets are batteries, thermal energy storage, solar-thermal heating (S2H), power-to-heat in the form of large-scale ground source heat pumps and electric/ electrode boilers, as well as power-to-gas.

The techno-economic analysis of Berlin's joint power and district heating system concludes that the plans by the BECP can only be partly supported. Indeed, Berlin's district heating network is maintained as envisaged by the BECP and operates continuously even during the summer season when only domestic hot water energy supply is required. There are no investments observed to shift heat generation to the sites of heat consumption by means of residential fuel fired or electric/ electrode boiler capacity, which could prevent

heat transmission losses. By transforming the district heating network toward lower supply and return temperatures, heat transmission losses can be reduced only slightly. At the same time, water mass flow rates must be increased to supply the same amounts of heat energy. The pumping energy grows with the power of three of this increase in water mass flow. However, given its small share in Berlin's total energy consumption, this increase is of little importance and is thus no obstacle to the transformation of the district heating network.

In contrast, the analysis shows no investments in local vRES, such as PV or wind power, as considered by the BECP, or in local capacities for battery or power-to-gas storage. These are investments that take place in the entire national power system and have no particular advantage in being located within the Berlin power and heating systems. Furthermore, the analysis cannot support a transformation in the form of a fuel switch from coal-fired CHP toward gas-fired CHP plants, since it shows no significant investments in CHP technology. In fact, with increasing RES penetration of the national power system, the share of power and heat produced in cogeneration decreases in Berlin's energy system and, thus, the role of CHP plants declines in the future years of the analysis. When the district heating maximum supply temperature is then lowered, this development is even more pronounced. Instead of investments in CHP plants, the analysis shows significant capacity expansions of conventional combined-cycle gas turbines to substitute oil and coal-fired CHP plants and to provide a back-up for scarcity of RES imports from the national power grid. In the business-as-usual scenario, without any additional CO_2 emissions constraints for the city, decommissions of coal-fired CHP capacity by 2030 occur only when the district heating maximum supply temperature is lowered to 90°C, as other heating technologies then become more likely to substitute CHP. In the BECP scenario, the additional CO_2 emissions constraints can force the decommissioning of coal-fired CHP capacity earlier than the end of 2030 even when the high temperature level in the district heating system is maintained. Yet, this development is more pronounced when the district heating maximum supply temperature is also lowered.

At elevated levels of RES penetration in the national power system in the future, power-to-heat provides a more economical heat supply in the Berlin district heating network than CHP. In 2015, the conventional power demand in Berlin amounted to about 13 TWh_{el}. In the BECP scenario with a maximum supply temperature of 140°C in the district heating network, power-to-heat causes an additional power demand that amounts to 0.8 TWh_{el}, 1.2 TWh_{el}, and 3.5 TWh_{el} at RES power system penetrations of 35%, 50%, and 80%, respectively. When lowering the district heating maximum supply temperature to 90°C, this demand is reduced to only 1.9 TWh_{el} at 80% RES penetration. This power demand is mainly driven by large-scale ground source heat pumps, accompanied to some degree by electric and biomass-fueled boilers in the district heating transmission network. Capacity investments and heat generation of ground source heat pumps increase with the RES penetration in the national power grid. When lowering the maximum supply temperature in the district heating network this increase is substantially greater. The analysis shows no further investments into gas-fired heat-only plants. Instead, the higher the RES penetration and the more the temperature level in district heating network is decreased, the more

existing gas-fired heat-only plants are decommissioned. In contrast, biomass-fueled heat-only plants expand to some degree. This shift from gas to biomass is explained by increasing fuel and emission costs of gas. Moreover, the results do not clearly indicate an investment need into thermal energy storage tanks or any investments into solar-thermal heating. In summary, CHP plants in Berlin can be substituted more economically by a mix of combined-cycle gas turbine plants, power imports, ground source heat pumps, and electric and biomass-fueled boilers. With the increase of the CO_2 emissions price, such an optimized mix can even undercut Berlin's 2050 CO_2 emissions targets in a business-as-usual scenario without imposing such an additional limit.

2 Power-to-heat for renewable energy integration: A review of technologies, modeling approaches, and flexibility potentials

Power-to-heat for renewable energy integration: A review of technologies, modeling approaches, and flexibility potentials

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Highlights

- We review model-based analyses of residential power-to heat options.
- We compare and categorize research scopes, methods, and findings.
- We identify state-of-the-art analytical model formulations.
- Findings: fossil fuel substitution, renewable integration, decarbonization.
- Heat pumps and passive thermal storage are particularly favorable options.

Abstract

A flexible coupling of power and heat sectors can contribute to both renewable energy integration and decarbonization. We present a literature review of model-based analyses in this field, focusing on residential heating. We compare geographical and temporal research scopes and identify state-of-the-art analytical model formulations, particularly concerning heat pumps and thermal storage. While numerical findings are idiosyncratic to specific assumptions, a synthesis of results indicates that power-to-heat technologies can cost-effectively contribute to fossil fuel substitution, renewable integration, and decarbonization. Heat pumps and passive thermal storage emerge as particularly favorable options.
Keywords: power-to-heat, renewable energy, decarbonization, heat pump, thermal energy storage
JEL codes: C61, D62, Q42
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2.1 Introduction

Not only since the 2015 Paris Agreement (UN, 2015), there is widespread consensus that the use of renewable energy sources (RESs) will play a major role in the global response to the threat of climate change. In particular, increasing shares of variable renewable energy sources (vRESs) such as wind and solar power have to be integrated in different end-use sectors. In this context, the coupling of power and heat sectors receives increasing attention of researchers and policymakers alike. Compared to other flexibility options and sector coupling strategies, linking the power and heat sectors is often considered to be particularly promising because both the costs of generating heat from electricity and the costs of heat storage are relatively low (Østergaard, 2012). Flexibly using renewable electricity for heating purposes may (i) help to decarbonize the heat sector and (ii) contribute to the power system integration of variable renewables by providing additional flexibility.

In many industrialized countries, decarbonizing the heating sector is a precondition for achieving ambitious climate policy targets; in particular, space heating accounts for substantial fractions of final energy demand and greenhouse gas emissions (Lucon et al., 2014). Compared to the electricity sector, the utilization of renewable energy sources lags behind in the heat sectors in many countries. For example, Germany is often considered as an international front-runner with respect to the utilization of wind and solar energy (Hake et al., 2015). By the end of 2016, the share of renewables in gross power consumption was nearly 32% in Germany, up from around 3% in the early 1990s. In contrast, the renewable share in final energy demand for heating and cooling was only around 13% in 2016, up from 2% in 1990 (Bauermann, 2016). Comparable developments can be observed in other industrialized countries.

The integration of variable renewable energy sources requires additional flexibility in the power system as the feed-in patterns of wind and solar power are only partly correlated with electricity demand (Lew et al., 2013; Perez-Arriaga and Batlle, 2012; Schill, Pahle, and Gambardella, 2017). There are many ways of providing such flexibility, for example, flexible thermal generators, various forms of energy storage[1], demand-side measures, grid-connected electric vehicles, geographical balancing facilitated by transmission, as well as changes in design, siting, and dispatch of variable renewables (Kondziella and Bruckner, 2016). While generating heat from electricity was traditionally not a preferred option in fossil fuel-based power systems, the flexible use of electricity for heating purposes, often combined with heat storage, has recently received increasing attention as another – and particularly promising – source of system flexibility (Stinner, Huchtemann, and Müller, 2016).

While the benefits and challenges of power-to-heat options in power systems with high shares of variable renewable energy sources are beginning to be understood, the literature is still heterogeneous: existing power system and market models have been extended, and new models have been developed; with applications focusing on various geographical contexts, time horizons, and technologies. To consolidate the evidence at hand and lay

[1] A review of electricity storage requirements for renewable energy integration is provided by Zerrahn and Schill (2017).

out avenues for future research, we devise a structured account of model-based analyses of different power-to-heat options in the international peer-reviewed literature. In particular, we compare scopes, methodologies, and research questions and aim to synthesize some common findings.

In doing so, we focus on power system effects of power-to-heat technologies in the residential heating sector and largely exclude industrial heat applications. We further focus on power-to-heat options, that is, turning electric into thermal energy, and not on the combined generation of heat and power (CHP). We do not consider other sector coupling strategies, for example, interactions between electric vehicle batteries and the power system (Richardson, 2013), or conversion paths like power-to-gas or power-to-liquids (Barton and Gammon, 2010; Manuel Götz et al., 2016; Schiebahn et al., 2015).

The remainder of this article is structured as follows. In Section 2.2, we categorize different power-to-heat options, that is, different approaches of using electricity in the residential heating sector. Section 2.3 introduces the methodology of our literature review. In Section 2.4, we discuss the research scope of model-based power-to-heat analyses in the international literature. Section 2.5 compares methodological approaches and introduces analytical model formulations of heat pumps and heat storage. In Section 2.6, we synthesize research questions and findings with respect to, among others, cost effectiveness, integration of variable renewables, and decarbonization. The final sections concludes, connects to some market trends, and hints toward future research directions.

2.2 Residential power-to-heat options

There are different means to convert electricity into heat. Figure 2.1 categorizes the most important options for the residential heating sector.

Following the categorization provided in Figure 2.1, we first distinguish between *centralized* and *decentralized* power-to-heat options. Under the centralized approach, electricity is converted into heat at a location that may be distant to the point of actual heat demand, and (district) heating networks are used to distribute the heat to where it is needed (Olsthoorn, Haghighat, and Mirzaei, 2016a). In contrast, decentralized power-to-heat options make use of electricity right at, or very close to, the location of heat demand. In reality, the line between centralized and decentralized options is blurred as, for example, heat may be jointly provided for only a few flats or houses in local or neighborhood heating networks (Henrik Lund, Werner, et al., 2014).

Second, some power-to-heat options involve thermal energy storage while others do not. Centralized options always come with some extent of storage because district heating networks have a certain thermal storage capacity (Z. Li et al., 2016). A heating network's storage capability may be further increased with dedicated (central) thermal storage facilities which, depending on the storage size, may also allow for seasonal storage. Decentralized options, in contrast, may come without energy storage, which we refer to as *direct heating*. Other decentralized options are combined with thermal energy storage (TES), referred to as storage heating or *TES-coupled heating*. Such thermal energy storage may be either internal or external with respect to the actual power-to-heat element. An example for *in-*

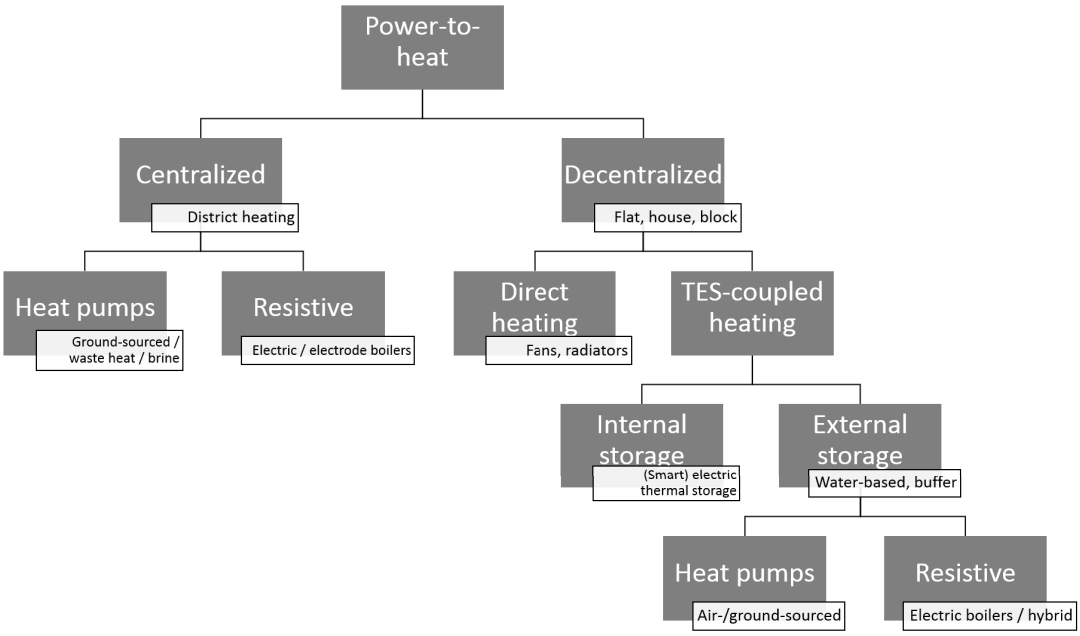

Figure 2.1: Categorization of residential power-to-heat options.

ternal thermal energy storage are electric storage heaters, which store thermal energy in a well-insulated solid medium such as ceramic bricks. If such systems are equipped with advanced communication and control equipment, they are also referred to as "smart" electric thermal storage (Wong and Pinard, 2017). An example for *external* thermal energy storage are hot water storage elements of standard water-based residential heating systems. Aside from such active thermal storage, which allows for controlled charging and discharging, there is also the option of passive thermal storage (not depicted in Figure 2.1). Here, thermal energy is stored in the building mass or the interior and released in a non-controlled way (Kensby, Trüschel, and Dalenbäck, 2015; Le Dréau and Heiselberg, 2016; Reynders, Nuytten, and Saelens, 2013).

Within these high-level categories, different technologies can be distinguished, among them various kinds of *heat pumps*[2] and *resistive* heaters. Centralized power-to-heat approaches either draw on large-scale heat pumps that make use of geothermal (i.e. ground-sourced) energy, waste heat or brine, or on large electric boilers, often in the form of electrode boilers. In general, these options are also available in the group of decentralized heating options coupled with external thermal energy storage. Here, smaller-scale heat pumps are usually air- or ground-sourced. Resistive heating comes in the form of electric boilers or electric heating elements in boilers that are primarily fueled by some other energy carrier such as natural gas. An example for the latter, which is also referred to as hybrid heating, is a water-based residential heating system with a boiler that is primarily

[2] A much-cited review on heat pumps is provided by Chua, Chou, and Yang (2010), a more recent one by Fischer and Madani (2017).

fueled with natural gas and has an additional electric heating element (Heinen, Burke, and O'Malley, 2016).

Particularly in the heat pump literature, a related classification distinguishes between monovalent, mono-energetic, and bivalent approaches (Fischer and Madani, 2017). For example, a monovalent system consists only of a heat pump which is designed to cover the full heating energy demand in all hours of the year. In a mono-energetic system, a heat pump may be complemented by an electric heating element, which allows for smaller heat pump dimensioning. Yet the energy source – i.e., electricity – does not change. In contrast, bivalent systems draw on two heating options with different energy carriers. An example for the latter is a heat pump in combination with a fossil-fueled backup boiler.

More indirect ways of electric heating, such as the conversion of electricity to hydrogen or methane which may then fuel a boiler, are not depicted in Figure 2.1 and are also not considered further in this review. Likewise, Figure 2.1 focuses on residential space heating and does not include details on domestic hot water (DHW) provision. Yet most of the depicted options, with the exception of (smart) electric thermal storage, may also be used to provide hot water.

Figure 2.2 illustrates the interconnection of different power-to-heat options with electricity and district heating networks. Centralized power-to-heat technologies draw electricity from the grid to generate heat, using either large-scale heat pumps or electric boilers. Heat energy is then transported to residential customers. In contrast, decentralized power-to-heat options do not make use of heating networks. Figure 2.2 also indicates that most power-to-heat options involve some energy storage capability.[3] From an energy system point of view, interactions between different kinds of heat storage and electricity storage technologies are of particular interest.

2.3 Methodology of this literature review

We conducted a systematic literature search of model-based analyses in leading peer-reviewed journals of applied and economic energy research. To this end, we first screened the journals *Applied Energy*, *Energy*, *Energy Economics*, *Energy Policy*, and *Renewable and Sustainable Energy Reviews* for the keywords *electric boiler*, *electric heating*, *electric thermal storage*, *heat pump*, and *power-to-heat*. A search in the Web of Science Database resulted in a total number of 721 articles that appeared between 2007 and 2016 in these journals. The keyword *heat pump* lead to the most hits, and *electric thermal storage* to the least hits. The number of articles featuring one or more of the keywords substantially increased between 2007 and 2016 as Figure 2.3 illustrates. This may be interpreted as an increasing academic relevance of power-to-heat analyses. Yet the overall number of articles appearing in these journals also grew. The share of keyword articles in overall articles, thus, increased only moderately from 1.2% in 2007 to 2.6% in 2016.

Within the retrieved articles, we carried out both forward and backward searches to identify relevant papers that the articles cite and are cited by. Thus, the scope of journals

[3] In addition, there may be a passive thermal energy storage capacity related to the building mass. This is not depicted in Figure 2.2.

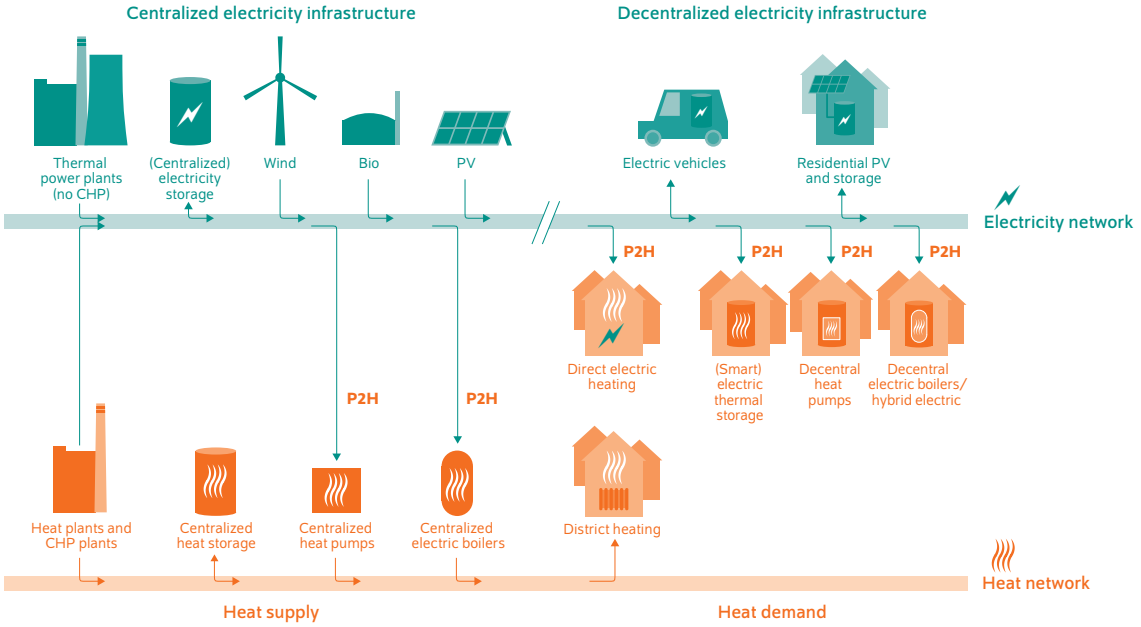

Figure 2.2: Interconnections of power-to-heat options with electricity and district heating networks.

Source: Own illustration inspired by Schulz (2011).

broadened to include further (and rather technology-oriented) outlets, among others *Energy and Buildings*, *Energy Conversion and Management* or *Journal of Cleaner Production*, and a few studies from the gray[4] literature. We took all papers into account that appeared, also online first, until January 1st, 2017. Out of this sample, we focused on the 46 articles that are most relevant with respect to this review, and examined and compared these in depth.

As we aim to provide a structured and detailed synthesis of the effects of power-to-heat technologies in power systems with renewable energy sources, the depth of this review must necessarily be traded off against its breadth: the main selection criteria were a traceable exposition and, for stringency of this review, a rather narrow focus on the techno-economic assessment of residential power-to-heat in the context of renewable energy integration. For instance, the large bodies of literature on household heating behavior and optimal design of specific residential heating systems do not enter this review article. Evidently, there is some level of discretion; we do not claim to render a complete account of all published research on the topic. Nonetheless, we aim to present a broad account of important approaches and findings.

[4]Some of these appeared as journal articles in 2017.

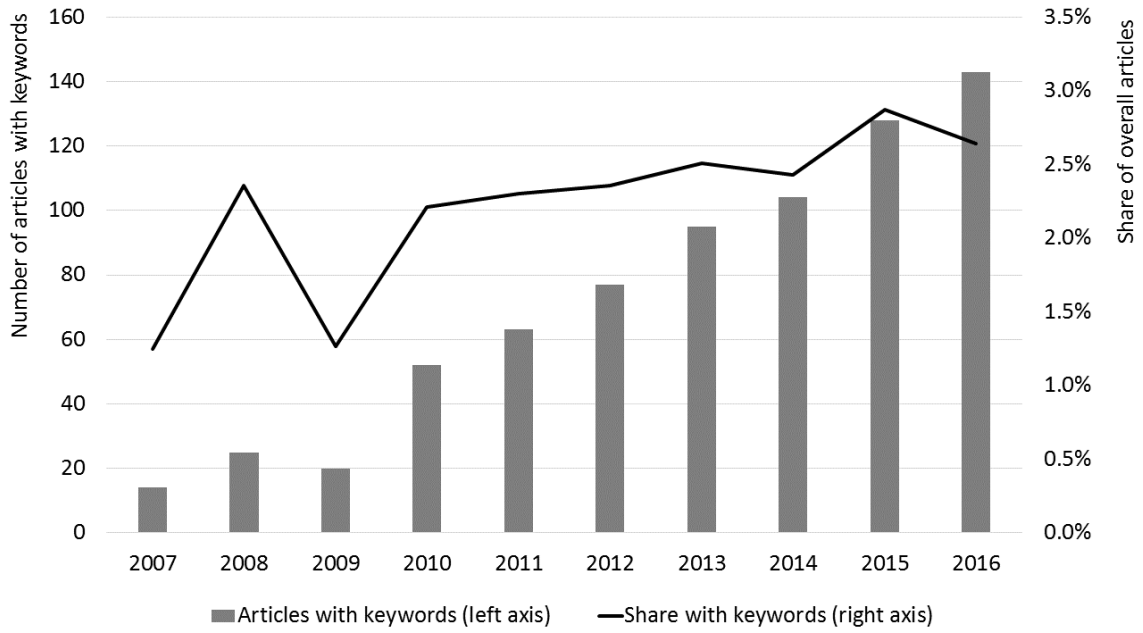

Figure 2.3: Articles featuring keywords in journal sample.

Source: Own calculations based on Web of Science data.

2.4 Research scope: what research focused on so far

The reviewed literature on residential power-to-heat for renewable energy integration is quite diverse. To provide some orientation, this section describes the temporal scope, geographical coverage as well as the analyzed technologies. See Table 2.1 for an overview.

Table 2.1: Research scope.

				Centralized heat		Decentralized heat				
Paper	**Geogr. scope**	**Time horizon**	**RES shares**	**Resistive/ heat pumps/ CHP**	**Heat storage**	**Resistive/ hybrid/ SETS**	**Heat pumps/ μ-CHP**	**Heat storage**	**Other sectors**	**Other features**
Arteconi et al. (2016)	Belgium (stylized)	2030	30%	-/-/-	-	✓/-/-	✓/-	passive, DHW	-	-
Bach et al. (2016)	Copenhagen	2013, 2015	n/s	-/✓/✓	✓	-/-/-	-/-	-	-	-
Barton, Huang, et al. (2013)	UK	2010-2050	n/s	-/-/-	-	✓/-/✓	✓/✓	passive, DHW, SETS	vehicles	-
Bauermann, Spiecker, and Weber (2014)	Germany	2010-2050	n/s	-/-/✓	-	-/-/-	✓/-	-	-	-
Blarke (2012)	West Denmark	2003-2010 (scenarios)	20%	✓/✓/✓	✓	-/-/-	-/-	-	(cooling)	-
Böttger, Mario Götz, Lehr, et al. (2014)	Germany	2015 - 2030	n/s	✓/-/-	-	-/-/-	-/-	-	-	
Böttger, Mario Götz, Theofilidi, et al. (2015)	Germany	2012, 2025	23%, 54%	✓/-/✓	✓	-/-/-	-/-	-	-	control power
Chen et al. (2014)	Beijing	2009-2020	0, 20, 40%	-/-/(✓)	-	✓/-/✓	✓/-	passive, SETS	-	-
Connolly, Henrik Lund, and Brian V. Mathiesen (2016)	EU-28	2050	up to 100%	✓/✓/✓	✓	✓/-/-	✓/✓	-	vehicles, cooling	-
Cooper et al. (2016)	UK	2020s, 2030s, 2050s	14, 25, 38%	-/-/-	-	-/-/-	✓/-	passive, DHW, active	-	-
Dodds (2014)	UK	2010-2050	n/s	-/-/✓	-	✓/-/✓	✓/✓	-	-	-
Ehrlich, Klamka, and Wolf (2015)	Germany	2020	n/s	-/-/-	-	-/✓/-	-/-	active	-	-
Fehrenbach et al. (2014)	Germany	2010-2050	endog.	-/-/✓	-	-/-/-	✓/✓	active	-	-
Georges et al. (2017)	Belgium	2016	n/s	-/-/-	-	(✓)/-/-	✓/-	passive, DHW	-	-
Hedegaard, B. Mathiesen, et al. (2012)	Denmark	2020	50%	(✓)/(✓)/✓	-	-/-/-	✓/-	active, passive	(vehicles)	-

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Table 2.1 – *Continued from previous page*

				Centralized heat		Decentralized heat				
Paper	**Geogr. scope**	**Time horizon**	**RES shares**	**Resistive/ heat pumps/ CHP**	**Heat stor-age**	**Resis-tive/ hybrid/ SETS**	**Heat pumps/ μ-CHP**	**Heat storage**	**Other sectors**	**Other features**
Hedegaard and Balyk (2013)	Denmark	2030	60%	✓/✓/✓	✓	✓/-/-	✓/-	passive, DHW, active	-	-
Hedegaard and Münster (2013)	Denmark	2030	50-60%	✓/✓/✓	✓	✓/-/-	✓/-	passive, (DHW), active	-	-
Heinen, Burke, and O'Malley (2016)	Ireland	2030	6 GW wind	-/-/-	-	✓/-	✓/✓/-	DHW, active	-	-
Henning and Palzer (2014) and Palzer and Henning (2014)	Germany	n/s (2050)	up to 100%	✓/-/✓	✓	✓/-/-	✓/✓	active	-	-
Hughes (2010)	Prince Edward Island, Canada	2002-2003	5.15 MW wind power	-/-/-	-	✓/-/✓	-/-	-	-	-
Kirkerud et al. (2014)	Norway, Sweden	2010-2012 (scenarios)	historical	✓/✓/-	-	✓/-/-	✓/-	-	-	-
Kiviluoma and Meibom (2010)	Finland	2035	8-29%	✓/✓/✓	✓	-/-/-	-/-	-	vehicles	-
J. Li et al. (2016)	Stylized urban	n/s	n/s	-/✓/✓	✓	-/-/-	-/-	-	-	-
D. Liu et al. (2016)	Beijing, Tianjin, Hebei	2015	n/s	✓/-/✓	-	-/-/-	-/-	-	-	-
Henrik Lund, Möller, et al. (2010)	Denmark	2020, 2040, 2060	Up to 100%	✓/✓/✓	-	✓/✓/-	✓/✓	-	cooling, ind. heat, transp., H_2	-
Brian V. Mathiesen and Henrik Lund (2009)	Denmark	2030	up to 100%	✓/✓/✓	✓	-/-/-	-/✓	-	vehicles, H_2	Control power
Merkel, Fehrenbach, et al. (2014)	Germany	2015-2050	endog.	-/-/-	-	-/-/-	✓/✓	active	-	-
Merkel, McKenna, et al. (2017)	Germany	2015-2050	60% (elec, heat)	-/ -/✓	-	-/-/-	✓/✓	active	-	-
Münster et al. (2012)	Denmark	2025	n/s	✓/✓/✓	✓	-/-/-	✓/-	-	-	-
Nielsen et al. (2016)	Copen-hagen	short-term scenarios	n/s	✓/✓/✓	✓	-/-/-	-/-	-	-	-

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Table 2.1 – *Continued from previous page*

Paper	Geogr. scope	Time horizon	RES shares	Centralized heat: Resistive/ heat pumps/ CHP	Centralized heat: Heat storage	Decentralized heat: Resistive/ hybrid/ SETS	Decentralized heat: Heat pumps/ μ-CHP	Decentralized heat: Heat storage	Other sectors	Other features
Østergaard, Brian Vad Mathiesen, et al. (2010)	Aalborg	2007, 2050	100%	-/✓/✓	✓	✓/-/-	✓/-	-	vehicles, cooling, H_2	Control power
Østergaard and Andersen (2016)	Denmark	2014	n/s	-/✓/✓	✓	-/-/-	✓/-	DHW	-	-
Østergaard and Henrik Lund (2011)	Frederikshavn	"long-term"	100%	-/✓/✓	✓	-/-/-	✓/✓	-	vehicles	-
Papaefthymiou, Hasche, and Nabe (2012)	Germany	2020, 2030	36, 47%	-/-/-	-	-/-/-	✓/-	passive	-	-
Patteeuw, Bruninx, Delarue, et al. (2015)	Belgium (stylized)	n/s	n/s	-/-/-	-	✓/-/-	✓/-	passive, DHW	-	-
Patteeuw, Bruninx, Arteconi, et al. (2015)	Belgium (stylized)	2030	20%	-/-/-	-	✓/-/-	✓/-	passive, DHW	-	-
Patteeuw, Reynders, et al. (2015)	Belgium (stylized)	2030	40%	-/-/-	-	-/-/-	✓/-	passive, DHW	-	-
Patteeuw and Helsen (2016)	Belgium	n/s*	10-100%	-/-/✓	-	✓/-/-	✓/-	passive, DHW, active	-	-
Patteeuw, Henze, and Helsen (2016)	Belgium (stylized)	2013	8-40%	-/-/-	-	✓/-/-	✓/-	passive, DHW	-	household behavior
Pensini, Rasmussen, and Kempton (2014)	PJM	n/s*	95%	-/✓/-	✓	✓/✓/-	-/-	active	-	-
Petrović and Karlsson (2016)	Denmark	2010-2050	50% wind	-/✓/-	-	✓/-/-	✓/-	-	transp., real economy	-
Salpakari, Mikkola, and P. D. Lund (2016)	Helsinki	2013-2015, 2050	60%	✓/✓/✓	✓	✓/-/-	-/-	active	-	-
Schaber, Steinke, and Hamacher (2013)	Germany	2020, 2050	n/s	-/-/✓	-	✓/-/-	(✓)/-	(active)	natural gas, H_2	-

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Table 2.1 – *Continued from previous page*

				Centralized heat		Decentralized heat				
Paper	**Geogr. scope**	**Time horizon**	**RES shares**	**Resistive/ heat pumps/ CHP**	**Heat stor-age**	**Resis-tive/ hybrid/ SETS**	**Heat pumps/ μ-CHP**	**Heat storage**	**Other sectors**	**Other features**
Teng, Aunedi, and Strbac (2016)	United Kingdom	2030, 2050	31% or 47% in 2030, 54% in 2050	-/-/-	-	-/-/-	✓/-	active	vehicles	stochastic; intertia-dependent frequency response
Waite and Modi (2014)	New York (City)	n/s*	up to 100% wind	-/-/-	-	-/-/-	✓/-	-	-	-

*Patteeuw and Helsen (2016) draw on input data of 2013-2016; Pensini, Rasmussen, and Kempton (2014) of 1999-2002; and Waite and Modi (2014) of 2005.
Notes: Check marks indicate central consideration of the technology, parentheses a secondary consideration. *Abbreviations:* DHW: domestic hot water; endog.: endogenous; μ-CHP: micro combined heat and power; n/s: not specified; SETS: smart electric thermal storage; transp.: transportation

Geographically, many applications focus on Northern and Western Europe. Within Europe, there is relatively broad evidence on the Nordic countries, specifically Denmark (Bach et al., 2016; Blarke, 2012; Hedegaard and Balyk, 2013; Hedegaard, B. Mathiesen, et al., 2012; Hedegaard and Münster, 2013; Brian V. Mathiesen and Henrik Lund, 2009; Münster et al., 2012; Nielsen et al., 2016; Østergaard and Andersen, 2016; Østergaard and Henrik Lund, 2011; Østergaard, Brian Vad Mathiesen, et al., 2010; Petrović and Karlsson, 2016); many studies also focus on Belgium (Arteconi et al., 2016; Georges et al., 2017; Patteeuw, Bruninx, Arteconi, et al., 2015; Patteeuw, Bruninx, Delarue, et al., 2015; Patteeuw and Helsen, 2016; Patteeuw, Henze, and Helsen, 2016; Patteeuw, Reynders, et al., 2015), Germany (Bauermann, Spiecker, and Weber, 2014; Böttger, Mario Götz, Lehr, et al., 2014; Böttger, Mario Götz, Theofilidi, et al., 2015; Ehrlich, Klamka, and Wolf, 2015; Fehrenbach et al., 2014; Henning and Palzer, 2014; Merkel, Fehrenbach, et al., 2014; Merkel, McKenna, et al., 2017; Palzer and Henning, 2014; Papaefthymiou, Hasche, and Nabe, 2012; Schaber, Steinke, and Hamacher, 2013) as well as the UK (Barton, Huang, et al., 2013; Cooper et al., 2016; Dodds, 2014; Teng, Aunedi, and Strbac, 2016) and Ireland (Heinen, Burke, and O'Malley, 2016). All countries have ambitious policies on long-term decarbonization targets, for the case of Denmark and Germany largely based on variable renewable energy sources, i.e. wind or solar photovoltaics (PV). Thus, research efforts are often directed toward managing the new electricity demand in the residential heating sector in a flexible way. Moreover, especially for Denmark, a developed district heating system calls for research efforts on specific de-carbonization potentials in this context.

Many studies have a long-term time horizon, often the years 2030 and 2050. Such long-term analyses allow the examination of scenarios with very high shares of renewables in electricity and heating sectors which will have adequately evolved instead of legacy systems shaped by currently installed capacities. Accordingly, many papers assume a renewables share of 40%-60% or higher. However, a number of studies do either not explicitly state the share of renewable energy sources or – if they do – do not specify the renewable technologies.

The range of heating technologies considered in the analyses is broad. Centralized heating may be provided by CHP plants, heat pumps, resistive heating or any combination of these technologies, often combined with heat storage. The papers differ greatly with respect to the level of technological detail; many applications represent technologies in a rather stylized way. Decentralized heating is likewise analyzed for a broad range of different technologies. Many analyses implement some stylized model of heat pumps or resistive electric heaters.[5] Hybrid heating technologies, explicitly considered in Ehrlich, Klamka, and Wolf (2015) and Pensini, Rasmussen, and Kempton (2014), and smart electric thermal storage (SETS), explicitly considered in Barton, Huang, et al. (2013), Chen et al. (2014), Dodds (2014), and Hughes (2010), are not in the focus of most papers. A large share of models also employs some kind of decentralized heat storage to shift heating energy in time, often differentiated into passive and active storage.

[5]The reviewed studies often do not differentiate or are not explicit on the difference between direct electric heating with fans or radiators and resistive TES-coupled heating, as categorized in Figure 2.1. We thus combined these approaches under the label *resistive* in column 7 of Table 2.1.

Beyond electricity and heating, not many papers take further sectors into account; some applications explicitly model the mobility sector (Barton, Huang, et al., 2013; Connolly, Henrik Lund, and Brian V. Mathiesen, 2016; Kiviluoma and Meibom, 2010; Brian V. Mathiesen and Henrik Lund, 2009; Østergaard and Henrik Lund, 2011; Østergaard, Brian Vad Mathiesen, et al., 2010; Petrović and Karlsson, 2016) or the cooling sector (Connolly, Henrik Lund, and Brian V. Mathiesen, 2016; Østergaard, Brian Vad Mathiesen, et al., 2010). While interactions between the electricity and heating sectors can thus be conveniently focused on, broadening the scope to include further sectors, which are likewise subject to de-carbonization, could provide complementary insights.

Some model analyses comprise additional features such as the provision of control power (Böttger, Mario Götz, Theofilidi, et al., 2015; Brian V. Mathiesen and Henrik Lund, 2009; Østergaard, Brian Vad Mathiesen, et al., 2010) and an explicit consideration of behavioral incentives for households (Patteeuw, Henze, and Helsen, 2016). Also here, implementing more markets or objectives could render a more detailed picture of the dual challenge of decarbonizing the energy sector(s) and providing the necessary flexibility.

2.5 Research methods and modeling approaches

2.5.1 Overview

Most publications considered in this review are techno-economic partial equilibrium models of the energy sector. These models simulate the operation – some also investments – of a power system over a defined time interval. The objective often follows a cost-minimization logic; assuming perfect competition and foresight among market actors, results can be interpreted as market equilibrium outcomes. Many models are long-standing projects that evolved from electricity sector analyses into combined heat-and-electricity-system analyses. Table 2.2 structures the reviewed papers according to the general method, the type of program, model name, time resolution, endogenous investments, and whether they provide explicit model formulations for power-to-heat and heat storage equations.

Table 2.2: Research method.

Paper	General method	Type of program	Model name	Time resolution	Endog. investments	Explicit formulations	
						P2H	Heat storage
Arteconi et al. (2016)	cost minimization	MILP	-	hourly, one year	-	(✓)	(✓)
Bach et al. (2016)	cost minimization	LP,	BALMOREL	hourly, 12 weeks	-	-	-
Barton, Huang, et al. (2013)	scenario assessment	n/a	FESA	hourly, one year	-	-	-
Bauermann, Spiecker, and Weber (2014)	cost minimization	stochastic LPs,	E2M2, HeatSyM	Time steps (days, hours)	power, heat	-	-
Blarke (2012)	cost minimization	MILP	COMPOSE	hourly, one year	-	-	-
Böttger, Mario Götz, Lehr, et al. (2014)	analysis of potentials	n/a	-	hourly, one year	-	-	-
Böttger, Mario Götz, Theofilidi, et al. (2015)	cost minimization	MILP	MICOES-Europe	hourly, one year	-	✓	✓
Chen et al. (2014)	minimization of residual demand variability	QP	-	hourly, one year	-	✓	✓
Connolly, Henrik Lund, and Brian V. Mathiesen (2016)	simulation	n/s	EnergyPLAN	hourly, one year	-	-	-
Cooper et al. (2016)	building simulation	n/s	-	one minute, (90 days)	-	-	-
Dodds (2014)	cost minimization	LP	UK MARKAL	72 time slices	(power), heat	-	-
Ehrlich, Klamka, and Wolf (2015)	cost minimization	LP	-	hourly, one year	-	✓	✓
Fehrenbach et al. (2014)	cost minimization	LP	TIMES	Time slices	power, heat	-	-
Georges et al. (2017)	flexibility maximization	MILP	-	15 minutes, 3.5 days	-	✓	✓
Hedegaard, B. Mathiesen, et al. (2012)	simulation	n/s	EnergyPLAN	hourly, one year	-	✓	✓
Hedegaard and Balyk (2013)	cost minimization	LP	BALMOREL, building add-on	hourly, 4 weeks	power, heat	✓	✓
Hedegaard and Münster (2013)	cost minimization	LP	BALMOREL, building add-on	hourly, 5 weeks	power, heat	-	-
Heinen, Burke, and O'Malley (2016)	cost minimization	LP	-	hourly	power, heat	✓	✓
Henning and Palzer (2014) and Palzer and Henning (2014)	iterative heuristic calibration	n/a	REMod-D	hourly, one year	-	✓	✓

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Table 2.2 – *Continued from previous page*

Paper	General method	Type of program	Model name	Time resolution	Endog. investments	Explicit formulations	
						P2H	Heat storage
Hughes (2010)	data analyses, heuristic simulation	n/a	-	hourly, one year	-	-	-
Kirkerud et al. (2014)	cost minimization	LP	BALMOREL	1,768 time slices, 52 weeks	-	-	-
Kiviluoma and Meibom (2010)	cost minimization	LP	BALMOREL	hourly, 26 weeks	power, heat	-	-
J. Li et al. (2016)	cost minimization	NLP	-	hourly, one year	-	✓	✓
D. Liu et al. (2016)	welfare maximization	LP	-	15 minutes, 2,880 hours	-	-	-
Henrik Lund, Möller, et al. (2010)	simulation	n/s	EnergyPLAN	hourly, one year	-	-	-
Brian V. Mathiesen and Henrik Lund (2009)	simulation	n/s	EnergyPLAN	hourly, one year	-	-	-
Merkel, Fehrenbach, et al. (2014)	cost minimization	MILP	TIMES, customized	hourly, 48 hours	heat	-	✓
Merkel, McKenna, et al. (2017)	cost minimization	MILP	TIMES-HEAT-POWER	6,048 hours (heat), 48 time slices (system)	power, heat	-	-
Münster et al. (2012)	cost minimization	LP,	BALMOREL	n/a	power, heat	-	-
Nielsen et al. (2016)	cost minimization	MILP	-	hourly, 24 hours	-	✓	✓
Østergaard, Brian Vad Mathiesen, et al. (2010)	simulation	n/s	EnergyPLAN	hourly	-	-	-
Østergaard and Andersen (2016)	dispatch simulation	n/a	energyPRO	hourly, one year	n/s	(✓)	(✓)
Østergaard and Henrik Lund (2011)	simulation	n/s	EnergyPLAN	hourly, one year	-	-	-
Papaefthymiou, Hasche, and Nabe (2012)	cost minimization	Stochastic MILP	PowerFys	hourly, one year	-	✓	✓
Patteeuw, Bruninx, Delarue, et al. (2015)	cost minimization	MILP	-	hourly, 48 hours	-	✓	✓
Patteeuw, Bruninx, Arteconi, et al. (2015)	cost minimization	MILP	-	hourly, 48 hours	-	✓	✓
Patteeuw, Reynders, et al. (2015)	cost minimization	MILP	-	hourly, one year	(power, heat)	-	-
Patteeuw and Helsen (2016)	cost minimization	MILP	-	hourly, one week	(power, heat)	✓	✓
Patteeuw, Henze, and Helsen (2016)	cost minimization	MILP	-	hourly, one year	-	✓	✓

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Table 2.2 – *Continued from previous page*

Paper	General method	Type of program	Model name	Time resolution	Endog. investments	Explicit formulations	
						P2H	Heat storage
Pensini, Rasmussen, and Kempton (2014)	(heuristic) cost minimization	n/a	-	hourly, 4 years	heat	-	-
Petrović and Karlsson (2016)	cost minimization	LP	TIMES-DK	time slices	power, heat	-	-
Salpakari, Mikkola, and P. D. Lund (2016)	minimization of residual load	MILP	-	hourly, 24 hours	-	✓	✓
Schaber, Steinke, and Hamacher (2013)	cost minimization	LP	URBS-D	hourly, 6 weeks	power, heat	-	-
Teng, Aunedi, and Strbac (2016)	cost minimization	MILP	ASUC	hourly, one year	-	-	-
Waite and Modi (2014)	dispatch simulation	LP, n/a	-	hourly, one year	(pre-optimization)	✓	-

Notes: Parentheses indicate a secondary consideration. *Abbreviations:* LP: linear program; MILP: mixed-integer linear program; NLP: non-linear program; n/a: not applicable; n/s: not specified; QP: quadratic program

An adequate additional treatment of the heat sector necessarily leads to new challenges in model formulation and computability. The majority of the reviewed articles are based on optimization, mostly cost minimization. Prominent examples are the models BALMOREL (Bach et al., 2016; Hedegaard and Balyk, 2013; Hedegaard and Münster, 2013; Kirkerud et al., 2014; Kiviluoma and Meibom, 2010; Münster et al., 2012), TIMES (Fehrenbach et al., 2014; Merkel, Fehrenbach, et al., 2014; Merkel, McKenna, et al., 2017; Petrović and Karlsson, 2016), and energyPLAN (Connolly, Henrik Lund, and Brian V. Mathiesen, 2016; Hedegaard, B. Mathiesen, et al., 2012; Brian V. Mathiesen and Henrik Lund, 2009; Østergaard and Henrik Lund, 2011; Østergaard, Brian Vad Mathiesen, et al., 2010). While the first two are cost minimization models, energyPLAN seeks to minimize consumption of fossil fuels. Other objectives comprise welfare maximization (D. Liu et al., 2016), the minimization of residual load variability (Chen et al., 2014) or some kind of flexibility maximization (Georges et al., 2017). Most models apply linear program (LP) or mixed-integer linear program (MILP) to carry out the optimization.

Among the MILP models, many analyses focus on the optimal operation of the power system; integer variables allow for a greater level of realism in the dispatch of technologies. Few MILP models additionally consider optimal investment decisions (Merkel, Fehrenbach, et al., 2014; Merkel, McKenna, et al., 2017; Patteeuw and Helsen, 2016; Patteeuw, Reynders, et al., 2015), which is computationally more convenient in LP approaches (Bauermann, Spiecker, and Weber, 2014; Dodds, 2014; Fehrenbach et al., 2014; Hedegaard and Balyk, 2013; Hedegaard and Münster, 2013; Heinen, Burke, and O'Malley, 2016; Kiviluoma and Meibom, 2010; Münster et al., 2012; Petrović and Karlsson, 2016; Schaber, Steinke, and Hamacher, 2013). This is also reflected in the temporal resolution: combining a MILP with endogenous investment decisions tends to come at the cost of a limited number of time slices compared to the other works. While most of the reviewed models have an hourly time resolution, many do not cover all hours of the year, but make use of some time aggregation strategy. Few models have a sub-hourly resolution (Cooper et al., 2016; Georges et al., 2017; D. Liu et al., 2016).

Some works do not rely on mathematical programming, but on heuristic methods (Barton, Huang, et al., 2013; Böttger, Mario Götz, Lehr, et al., 2014; Cooper et al., 2016; Henning and Palzer, 2014; Østergaard and Andersen, 2016; Palzer and Henning, 2014; Pensini, Rasmussen, and Kempton, 2014; Waite and Modi, 2014). Here, technologies are dispatched according to pre-specified hierarchies in case of renewable energy surplus or shortage for a number of scenarios with different data sets for demand, generation capacities or prices (Barton, Huang, et al., 2013; Pensini, Rasmussen, and Kempton, 2014; Waite and Modi, 2014). For instance, Barton, Huang, et al. (2013) apply, in case of shortages, a priority list which ranks storage discharging in the first place, followed by imports, dispatchable generation, and finally load shedding. In contrast, power surpluses are first used for storage charging, followed by fuel replacement in industry, power-to-heat instead of fuel-to-heat, and finally hydrogen production. In their greenfield simulation for Germany, Henning and Palzer (2014) and Palzer and Henning (2014) design an iterative calibration process. They aim to find optimal capacities of different energy conversion technologies and energy efficiency measures in buildings. Also here, the operation of all conversion

capacities follows a strict hierarchy favoring the use of renewable primary energies and higher conversion efficiencies. Costs are calculated subsequently in order to compare the simulations.

In addition, some papers explicitly devise specific mathematical formulations to represent heat pumps and heat storage in power system models. In the following, we discuss some common and some more elaborated approaches. See Table 2.3 for an overview of the most important nomenclature.

2.5.2 Formulations for modeling heat pumps

Heat pumps: coefficient of performance

Equation (2.1a) is the basic approach to represent electrical heat pumps. It assumes a constant relation between power input P_t and heat output $\dot{Q}_t^{HP}$, the average coefficient of performance (COP) $COP^{average}$, at any point in time t (Barton, Huang, et al., 2013; Blarke, 2012; Chen et al., 2014; Fehrenbach et al., 2014; Hedegaard, B. Mathiesen, et al., 2012; Hedegaard and Münster, 2013; Henning and Palzer, 2014; Kiviluoma and Meibom, 2010; Nielsen et al., 2016; Patteeuw, Bruninx, Delarue, et al., 2015; Patteeuw, Reynders, et al., 2015; Petrović and Karlsson, 2016). This formulation is simple and allows convenient computability when there are negligible variations in the COP over time (Petrović and Karlsson, 2016).

$$P_t = \frac{\dot{Q}_t^{HP}}{COP^{average}} \ \forall\ t, \tag{2.1a}$$

However, in reality the COP strongly depends on the temperature levels of the energy source, T^{source}, and sink, T^{sink}, as expressed by the Carnot-COP, $COP^{carnot} = \frac{T^{sink}}{T^{sink}-T^{source}}$. A low source temperature as well as high sink temperature lead to a lower coefficient of performance, which can cause a pronounced increase of the required power input or operational problems for heat pumps; for instance, in cold winters when the energy source is environmental air or when high supply temperatures are required. This may apply to centralized heat pumps feeding into conventional district heating networks, conventional radiator-based domestic distribution systems, or domestic hot water supply, which requires a certain minimum temperature to prevent legionella bacteria.

Formulation (2.1b) aims to capture this temperature dependence. Furthermore, a quality grade defined as $\phi := \frac{COP^{real}}{COP^{carnot}}$ can account for technical progress, where COP_t^{carnot} expresses the theoretically achievable coefficient of performance according to the temperature conditions and COP_t^{real} the technically feasible coefficient of performance. By 2014, such quality grades amounted to 0.24 to 0.45 (Kaltschmitt, Streicher, and Wiese, 2014).

$$COP_t^{real} = \phi \cdot COP_t^{carnot} = \phi \cdot \frac{T_t^{sink}}{T_t^{sink} - T_t^{source}} \ \forall\ t \tag{2.1b}$$

Several reviewed models (Bach et al., 2016; Papaefthymiou, Hasche, and Nabe, 2012; Patteeuw, Bruninx, Delarue, et al., 2015; Patteeuw and Helsen, 2016) apply such formula-

Table 2.3: Nomenclature: most important variables and parameters for modeling heat pumps, electric boilers and heat storage.

Symbol	Unit	Technology*	Explanation
Selected abbreviations			
DHW			Domestic hot water
EB			Electric boiler
HP			Heat pump
SH			Space heating
Variables			
P	kW	Heat pump	Electrical power input
$\dot{Q}$	kW		Heat transfer rate
$\dot{Q}^{C}$	kW	Heat storage	Energy per period charged to storage
$\dot{Q}^{D}$	kW	Heat storage	Energy per period discharged from storage
$\dot{Q}^{EB}$	kW	Electric boiler	Heat output
$\dot{Q}^{HP}$	kW	Heat pump	Heat output
S	kWh	Heat storage	State of charge
Parameters			
A	m^2	Heat storage	Exposed surface
C	kWh/K	Heat storage	Heat capacity of storage medium (e.g. water)
c	kWh/(kg K)	Heat storage	Specific heat capacity of storage medium
COP	≥ 0	Heat pump	Coefficient of performance
$l^{dynamic}$, l^{static}	[0;1]	Heat storage	Storage losses (dynamic, static)
$\overline{P}^{\dagger}$	kW	Heat pump	Maximum electrical power input
$\overline{Q^{EB}}^{\dagger}$	kW	Electric boiler	Maximum heat output
$\overline{Q^{HP}}^{\dagger}$	kW	Heat pump	Maximum heat output
$\overline{Q^{C}}^{\dagger}$	kW	Heat storage	Maximum charging restriction
$\overline{Q^{D}}^{\dagger}$	kW	Heat storage	Maximum discharging restriction
$\overline{S}^{\dagger}$	kWh	Heat storage	Maximum stored energy
$T^{\ddagger}$	K		Temperature
T^{a}	K		Ambient temperature
$T^{S\ddagger}$	K	Heat storage	Temperature of storage medium
T^{sink}	K	Heat pump	Temperature of the energy sink
T^{source}	K	Heat pump	Temperature of the energy source
$\Delta T^{\ddagger}$	K		Temperature difference
U	kW/(K m^2)	Heat storage	Heat transfer coefficient
$\overline{V}^{\dagger}$	m^3	Heat storage	Physical storage volume
η	[0;1]		Efficiency, e.g. of electric resistance heaters
ϕ	[0;1]	Heat pump	Quality grade as ratio of real COP to Carnot-COP
ρ	kg/m^3	Heat storage	Density of storage medium (e.g. water)

Notes: Variables and parameters used only in specific modeling approaches are explained in the text upon appearance. *: Blanks indicate relevance across technologies; †: Can also be a variable in investment models; ‡: Can also be a variable, depending on the specific context.

tions. Accounting for temperature dependence, relation (2.1a) transforms to (2.1c).

$$P_t = \frac{\dot{Q}_t^{HP}}{COP_t^{real}} = \frac{\dot{Q}_t^{HP}}{\phi \cdot \frac{T_t^{sink}}{T_t^{sink} - T_t^{source}}} \ \forall \ t \tag{2.1c}$$

However, this formulation represents only an approximation; in reality, the supply temperature of a heating system, T^{sink}, is affected by the heat output $\dot{Q}^{HP}$. Treating COP^{real} as an endogenous variable instead of an exogenous parameter leads to a non-linearity and, thus, to considerably higher computational effort. Verhelst et al. (2012) suggest to pre-calculate COP^{real} as a parameter by assuming an expected value for T^{sink} and given values for T_t^{source}, as done in all cases found here applying a temperature dependent COP. Alternatively, Heinen, Burke, and O'Malley (2016) suggest assuming a linear relationship between the hourly COP and the ambient temperature T_t^a according to (2.1d), where empirical data determines the slope parameter m. Furthermore, they fit this relation to a fixed coefficient of performance as input, COP^{input}, at a specific reference temperature of 7°C (280.15 K).

$$COP_t(T^a) = m \cdot (T_t^a - 280.15[K]) + COP^{input} \tag{2.1d}$$

In order to capture higher efficiency in part-load mode and larger flexibility for load following of variable-speed heat pumps, Georges et al. (2017) suggest a piece-wise linearization of the non-linear problem described by Verhelst et al. (2012). Salpakari, Mikkola, and P. D. Lund (2016), who analyze the use of large-scale heat pumps in district heating networks, constrain heat pump use on the network's exogenous supply temperature and allow operation only below 90°C. The coefficient of performance is then treated as a constant parameter, which might be a justified assumption in the context of large-scale heat pumps with a stable heat energy source. Appendices A.1.1 and A.1.2 present a detailed formulation for both suggestions.

Heat pumps with auxiliary electric boilers

Several articles provide formulations for the use of auxiliary electric boilers (EB). For instance, Patteeuw, Bruninx, Delarue, et al. (2015) augment the standard approach (2.1a) to formulation (2.1e) and additionally distinguish between space heating (SH) and domestic hot water (DHW) applications. Heat output is limited through further constraints on maximum power consumption of the heat pump and electric boiler.

$$P_t = \frac{\dot{Q}_t^{HP,SH}}{COP^{SH}} + \frac{\dot{Q}_t^{EB,SH}}{\eta^{EB}} + \frac{\dot{Q}_t^{HP,DHW}}{COP^{DHW}} + \frac{\dot{Q}_t^{EB,DHW}}{\eta^{EB}} \ \forall \ t \tag{2.1e}$$

Waite and Modi (2014) integrate the performance of an auxiliary electric boiler into the COP pre-calculation. Its operation is triggered by help of a minimum design temperature; Appendix A.1.3 provides further details. Also Hedegaard and Balyk (2013) assume that the heating capacity of heat pumps is generally complemented with some electric boiler capacity for peak loads, which reduces investment costs. In their investment model, they

specify a fixed ratio of heat pump capacity, $\overline{Q^{HP}}$, to auxiliary electric boiler capacity, $\overline{Q^{EB}}$, imposed by constraint (2.1f). Parameter cs^{HP} specifies this relationship; they suggest values between 0.72 to 0.82. For instance, if $cs^{HP} = 0.8$, then for each $100\,\mathrm{kW_{el}}$ of heat pumps, $25\,\mathrm{kW_{el}}$ of auxiliary electric boilers must be installed.

$$\overline{Q^{HP}} = \frac{cs^{HP}}{1 - cs^{HP}} \cdot \overline{Q^{EB}} \tag{2.1f}$$

2.5.3 Formulations for modeling heat storage

Technologies for heat storage are subject to different layouts, depending on their specific use. They may require different minimum temperature levels, which can have an impact on storage losses or on whether heat pumps can be connected to the storage. For instance, domestic hot water storage generally requires higher temperature levels, due to hygienic standards, than buffer tanks for conventional individual space heating. Floor heating systems require even lower temperatures.

Basic model

Most models implement such different kinds of storage according to a standard formulation (2.2), as found in Hedegaard, B. Mathiesen, et al. (2012), Heinen, Burke, and O'Malley (2016), Henning and Palzer (2014), Nielsen et al. (2016), Patteeuw and Helsen (2016), and Salpakari, Mikkola, and P. D. Lund (2016). It comprises a state-of-charge equation (2.2a), with storage energy level S and periodically charged and discharged energy, $\dot{Q}^C$ and $\dot{Q}^D$, as well as a constraint on maximum storage energy $\overline{S}$ (2.2b). Some analyses specify the maximum storage capacity with the storage volume $\overline{V}$ in cubic meters as limiting parameter (2.2c), (Heinen, Burke, and O'Malley, 2016; Henning and Palzer, 2014), where c, ρ, and ΔT represent the specific heat capacity of water, its density, and temperature difference, respectively. Charging and discharging capacity constraints, (2.2d) - (2.2e), are rather found for larger heat storage for district heating. An alternative to energy levels is the use of temperature levels (Ehrlich, Klamka, and Wolf, 2015; Henning and Palzer, 2014).

$$S_{t+1} = (1 - l^{static}) \cdot S_t + \dot{Q}_t^C - l^{dynamic} \cdot \dot{Q}_t^D \qquad \forall\, t \tag{2.2a}$$

$$S_t \leq \overline{S} \qquad \forall\, t \tag{2.2b}$$

$$\overline{S} = c \cdot \rho \cdot \Delta T \cdot \overline{V} \qquad \forall\, t \tag{2.2c}$$

$$\dot{Q}_t^C \leq \overline{Q^C} \qquad \forall\, t \tag{2.2d}$$

$$\dot{Q}_t^D \leq \overline{Q^D} \qquad \forall\, t \tag{2.2e}$$

There are different ways to account for storage losses; either only stationary losses l^{static} are considered (Ehrlich, Klamka, and Wolf, 2015; Hedegaard and Balyk, 2013; Hedegaard, B. Mathiesen, et al., 2012; Heinen, Burke, and O'Malley, 2016; Patteeuw and Helsen, 2016), or stationary as well as dynamic losses $l^{dynamic}$ (Henning and Palzer, 2014). Patteeuw and Helsen (2016) separate stationary heat losses in two parts: one proportional to the energy

actually stored, the other one proportional to the storage size. In case of large heat storage devices for district heating, stationary losses are sometimes neglected (Nielsen et al., 2016; Salpakari, Mikkola, and P. D. Lund, 2016).

Alternatively, Henning and Palzer (2014) and Palzer and Henning (2014) apply a differential equation for the storage energy content (2.3a) and its stationary losses (2.3b). The storage energy level is represented by the product of the storage's constant total heat capacity C^S and its temperature change over time $\frac{dT^S}{dt}$. Stationary heat losses $\dot{Q}^{loss}$ depend on the temperature difference between storage and environment, $T^S - T^a$. Furthermore, they define a time lag τ, which is rather long (180 days) for large centralized seasonal storage and small for decentralized short-term storage (72 hours), to replace the constant heat loss coefficient $U \cdot A$ consisting of the heat transfer coefficient U resulting from the storage's insulation material and its exposed surface A.

$$C^S \cdot \frac{dT^S}{dt} = l^{dynamic} \cdot \dot{Q}^C - \dot{Q}^D - \dot{Q}^{loss} \tag{2.3a}$$

$$\dot{Q}^{loss} = U \cdot A \cdot (T^S - T^a) = \frac{C^S}{\tau} \cdot (T^S - T^a) \tag{2.3b}$$

Heat storage in district heating systems

For district heating, different network levels can be considered. Nielsen et al. (2016) apply the standard formulation (2.2) for two types of heat accumulation tanks in district heating: one on the transmission, the other on the distribution level with lower supply temperature. The former is connected to CHP plants and electric boilers with charging and discharging constraints according to (2.2d) and (2.2e), the latter can be charged by the transmission network, heat pumps or electric boilers and has no charge or discharge constraints for storage. Salpakari, Mikkola, and P. D. Lund (2016) additionally consider the storage capability of the network. They introduce a heat demand surplus, which allows for heat accumulation by increasing the storage level in the following time step.

Passive heat storage

Hedegaard, B. Mathiesen, et al. (2012) apply the standard approach (2.2) to passive building mass storage and formulate the charging and discharging restrictions depending on a pre-specified temperature delta $\Delta T^{passive}$ for the building mass (2.4). This $\Delta T^{passive}$ captures the maximum temperature difference between the inside air temperature and the temperature of the building shell. Multiplied with the heat transfer coefficient U and the exposed surface A, this renders the maximum storage charging and discharging capacity. Moreover, this maximum capacity is restrained by the state of charge: in case the storage state of charge of the previous time step is at its maximum level, $S_{t-1} = \overline{S}$, the storage charging variable $\dot{Q}_t^C$ is restricted to zero, which is achieved by constraint (2.4a). In contrast, the discharging variable $\dot{Q}_t^D$ is not further restricted, as constraint (2.4b) prescribes. Conversely, if the passive storage level is zero, $S_{t-1} = 0$, then no heat can be discharged, and charging is possible at the maximum rate. For instance, if $\frac{S_{t-1}}{\overline{S}} = 0.9$, only this share

of heat can be discharged in a time step, and only ten percent of the maximum capacity can be charged.

$$\dot{Q}_t^C \leq U \cdot A \cdot \Delta T^{passive} \cdot \left(1 - \frac{S_{t-1}}{\overline{S}}\right) \qquad \forall\, t \tag{2.4a}$$

$$\dot{Q}_t^D \leq U \cdot A \cdot \Delta T^{passive} \cdot \frac{S_{t-1}}{\overline{S}} \qquad \forall\, t \tag{2.4b}$$

Flexibility can also be provided by a room temperature target window. The formulation by Hedegaard and Balyk (2013) comprises radiators and floor heating and accounts for another degree of flexibility provided by the passive energy storage capacity of the building mass. The temperature window is modeled by (2.5a) and (2.5b), where the actual room temperature T_t^I is a variable that may deviate from a reference temperature $T^{I,ref}$ within an interval $\left[\underline{T^I}, \overline{T^I}\right]$. A fraction $\frac{HS^{inv}}{HS^{tot}}$ of the residential building stock is equipped with control equipment to make use of this flexibility source. Equations (2.5c) to (2.5f) model the influence of exogenous shocks, such as heat from inhabitants or electrical appliances $\dot{Q}_t^{P+A}$, ventilation $\dot{Q}_t^{Ven}$, ambient temperature T_t^a, and endogenous decisions on heating technologies $\dot{Q}_t^{HT}$. The lower the ambient temperature T_t^a, the more heat $\dot{Q}_t^{BO}$ escapes from the passive building storage (2.5e), thus reducing its temperature level T_t^B. In turn, more heat $\dot{Q}_t^{BI}$ is transferred from the interior into the building mass (2.5d). Parameters A, C and U render the exposed surface, heat capacity and heat transfer coefficient for inner masses (I) and building mass (B).

$$T_t^I \geq T^{I,ref} + \left(\underline{T^I} - T^{I,ref}\right) \cdot \frac{HS^{inv}}{HS^{tot}} \qquad \forall\, t \tag{2.5a}$$

$$T_t^I \leq T^{I,ref} + \left(\overline{T^I} - T^{I,ref}\right) \cdot \frac{HS^{inv}}{HS^{tot}} \qquad \forall\, t \tag{2.5b}$$

$$T_{t+1}^I = T_t^I + \frac{\dot{Q}_t^{HT} + \dot{Q}_t^{P+A} + \dot{Q}_t^{S,loss} - \dot{Q}_t^{Ven} - \dot{Q}_t^{IB}}{C^I \cdot A} \qquad \forall\, t \tag{2.5c}$$

$$\dot{Q}_t^{IB} = U^{IB} \cdot A \cdot \left(T_t^I - T_t^B\right) \qquad \forall\, t \tag{2.5d}$$

$$\dot{Q}_t^{BO} = U^{BO} \cdot A \cdot \left(T_t^B - T_t^a\right) \qquad \forall\, t \tag{2.5e}$$

$$T_{t+1}^B = T_t^B + \frac{\dot{Q}_t^{IB} - \dot{Q}_t^{BO}}{C^B \cdot A} \qquad \forall\, t \tag{2.5f}$$

Chen et al. (2014), Papaefthymiou, Hasche, and Nabe (2012), and Patteeuw, Bruninx, Delarue, et al. (2015) also apply this concept. Specifically, the latter synthesize a virtual electric storage in a power system based on the aggregated building mass equipped with heat pumps. To this end, they derive room temperatures from a building simulation and use those as reference room temperatures T_t^{ref} in an electricity market model without building mass storage. In a second step, they introduce a comfortable room temperature window (2.6b), taking into account passive building mass storage. The temperature delta ΔT_t between T_t^{ref} and T_t in the second calculation is limited through a linear relationship

with the power input delta ΔP_t in equation (2.6a) and its capacity constraint (2.6c). The demand response operation of heat pumps is thus modeled as equivalent energy storage. This two-step approach offers two advantages: (i) advanced models for thermal behavior of buildings can be applied as the reference operation is computed separately; and (ii) linear models can be used to incorporate this type of demand response, which is defined as deviation from the reference case, allowing the use of typical dispatch models.

$$\Delta T_t = \frac{1}{C^{tot} \cdot COP_t} \cdot \Delta P_t \qquad \forall\, t \tag{2.6a}$$

$$\underline{T}_t \leq T_t \leq \overline{T}_t \qquad \forall\, t \tag{2.6b}$$

$$0 \leq P_t^{ref} + \Delta P_t \leq \overline{P} \qquad \forall\, t \tag{2.6c}$$

State-space model

With varying co-authors, Patteeuw developed a state-space representation of residential heating demand that can be integrated into economic system optimization models (Patteeuw, Bruninx, Arteconi, et al., 2015; Patteeuw, Bruninx, Delarue, et al., 2015; Patteeuw and Helsen, 2016; Patteeuw, Henze, and Helsen, 2016; Patteeuw, Reynders, et al., 2015). The vector $T_{s,t}$ captures the temperature state of the indoor air, floor, walls and the roof for each building (class) s in period t. Temperatures in the next period depend on the temperatures in the current period, where thermal conductances and capacities are summarized in matrix $\mathbf{A}$. Moreover, vector $\dot{Q}_{s,t}$ contains all heat inputs to the system, consisting of solar irradiation, internal heat gains, outside and ground temperature as well as heat gains from heating devices, transmitted with factors summarized in matrix $\mathbf{B}$. Heat dynamics are thus given by 2.7.

$$T_{s,t+1} = \mathbf{A}T_{s,t} + \mathbf{B}\dot{Q}_{s,t} \tag{2.7}$$

Together with constraints on the thermal comfort level $\underline{T} \leq T_{s,t}^I \leq \overline{T}$, where the indoor air temperature $T_{s,t}^I$ is an element of vector $T_{s,t}$, this set of linear equations can be plugged into dispatch and investment optimization models of the energy system to capture relevant interactions.

2.6 Research questions and findings

2.6.1 Overview

The reviewed articles on power-to-heat not only differ with respect to technologies, research scopes, and methodologies, but also aim to answer distinct research questions. Most papers provide evidence on the potential of residential power-to-heat options for the system integration of variable renewable energy sources. A closely related research focus is the contribution to decarbonizing the energy sector. Cost effectiveness is another research focus and an important criterion to judge different technologies or policies; in fact, the majority of analyses are optimization exercises aiming to reduce overall system costs of

operation and, partly, investments. It is difficult though to disentangle these three objectives because they mutually influence each other. For instance, cost effectiveness can be seen both as a primary goal under constraints on renewable energy use or decarbonization, and as a criterion to compare different scenarios of renewable energy integration. Beyond that, some analyses investigate the structure of heat supply, additional electricity demand of power-to-heat applications, and the impact on power prices. Moreover, some of the articles put emphasis on the development and presentation of a model or particular model features.

Table 2.4 summarizes the research questions. It indicates for all selected papers whether there is a distinct emphasis on particular research questions; parentheses indicate a secondary focus.

Table 2.4: Research focus and questions.

Paper	Cost effectiveness	RES integration	Decarbonization	Power prices	Electricity demand for P2H	Structure of heat supply	Methodological contribution
Arteconi et al. (2016)	✓	✓	-	✓	-	-	-
Bach et al. (2016)	(✓)	(✓)	-	(✓)	-	✓	(✓)
Barton, Huang, et al. (2013)	-	(✓)	✓	-	✓	-	-
Bauermann, Spiecker, and Weber (2014)	-	-	-	✓	-	✓	✓
Blarke (2012)	(✓)	(✓)	(✓)	-	-	-	-
Böttger, Mario Götz, Lehr, et al. (2014)	-	✓	-	-	(✓)	-	-
Böttger, Mario Götz, Theofilidi, et al. (2015)	✓	(✓)	✓	(✓)	-	-	✓
Chen et al. (2014)	✓	✓	✓	-	(✓)	-	-
Connolly, Henrik Lund, and Brian V. Mathiesen (2016)	(✓)	✓	✓	-	✓	(✓)	-
Cooper et al. (2016)	-	-	-	-	✓	(✓)	-
Dodds (2014)	(✓)	-	(✓)	-	-	✓	✓
Ehrlich, Klamka, and Wolf (2015)	-	(✓)	-	(✓)	-	-	✓
Fehrenbach et al. (2014)	(✓)	(✓)	(✓)	-	-	✓	(✓)
Georges et al. (2017)	-	-	-	-	-	-	✓
Hedegaard, B. Mathiesen, et al. (2012)	(✓)	✓	(✓)	-	-	-	(✓)
Hedegaard and Balyk (2013)	(✓)	(✓)	-	(✓)	-	-	✓
Hedegaard and Münster (2013)	✓	✓	(✓)	-	-	-	-
Heinen, Burke, and O'Malley (2016)	✓	(✓)	(✓)	-	-	✓	✓
Henning and Palzer (2014) and Palzer and Henning (2014)	✓	✓	(✓)	-	-	-	✓
Hughes (2010)	-	✓	(✓)	-	-	-	-
Kirkerud et al. (2014)	-	-	-	✓	✓	-	-
Kiviluoma and Meibom (2010)	✓	✓	✓	-	-	✓	-
J. Li et al. (2016)	✓	(✓)	-	-	-	-	✓
D. Liu et al. (2016)	✓	✓	(✓)	-	-	-	✓
Henrik Lund, Möller, et al. (2010)	(✓)	✓	✓	-	-	-	-
Brian V. Mathiesen and Henrik Lund (2009)	✓	✓	(✓)	-	-	(✓)	
Merkel, Fehrenbach, et al. (2014)	(✓)	-	-	-	-	✓	✓
Merkel, McKenna, et al. (2017)	(✓)	-	✓	-	✓	✓	-
Münster et al. (2012)	(✓)	(✓)	-	-	-	✓	✓
Østergaard and Andersen (2016)	-	-	-	(✓)	-	(✓)	✓

Continued on next page

Table 2.4 – *Continued from previous page*

Paper	**Cost effectiveness**	**RES integration**	**Decarbonization**	**Power prices**	**Electricity demand for P2H**	**Structure of heat supply**	**Methodological contribution**
Østergaard, Brian Vad Mathiesen, et al. (2010)	(✓)	✓	✓	-	-	(✓)	-
Østergaard and Andersen (2016)	✓	-	-	-	(✓)	(✓)	(✓)
Østergaard and Henrik Lund (2011)	(✓)	✓	(✓)	-	-	✓	-
Papaefthymiou, Hasche, and Nabe (2012)	✓	(✓)	✓	-	-	-	✓
Patteeuw, Bruninx, Delarue, et al. (2015)	-	-	-	-	-		✓
Patteeuw, Bruninx, Arteconi, et al. (2015)	(✓)	-	-	(✓)	✓	-	✓
Patteeuw, Reynders, et al. (2015)	✓	✓	✓	-	✓	-	-
Patteeuw and Helsen (2016)	✓	(✓)	✓	-	-	✓	✓
Patteeuw, Henze, and Helsen (2016)	✓	✓	(✓)	(✓)	-	-	✓
Pensini, Rasmussen, and Kempton (2014)	✓	✓	(✓)	-	-	✓	-
Petrović and Karlsson (2016)	✓	(✓)	(✓)	-	-	✓	(✓)
Salpakari, Mikkola, and P. D. Lund (2016)	-	✓	-	-	-	-	✓
Schaber, Steinke, and Hamacher (2013)	✓	✓	(✓)	-	✓	-	-
Teng, Aunedi, and Strbac (2016)	✓	✓	✓	-	-	-	-
Waite and Modi (2014)	(✓)	✓	(✓)	-	(✓)	-	(✓)

Note: Parentheses indicate a secondary consideration.

2.6.2 Cost effectiveness

A common finding of many reviewed articles is that power-to-heat applications have the potential to cost-effectively integrate high shares of variable renewable electricity into the energy system. Cost reductions are driven by (i) the substitution of fossil fuels (Arteconi et al., 2016; Connolly, Henrik Lund, and Brian V. Mathiesen, 2016; Hedegaard, B. Mathiesen, et al., 2012; Hedegaard and Münster, 2013; Heinen, Burke, and O'Malley, 2016; Østergaard and Andersen, 2016; Papaefthymiou, Hasche, and Nabe, 2012; Petrović and Karlsson, 2016; Schaber, Steinke, and Hamacher, 2013); (ii) better use of capital invested in renewable assets by means of reduced curtailment (Chen et al., 2014; Heinen, Burke, and O'Malley, 2016; J. Li et al., 2016; D. Liu et al., 2016; Patteeuw and Helsen, 2016; Pensini, Rasmussen, and Kempton, 2014; Waite and Modi, 2014); (iii) less need for costly auxiliary technologies such as peak-load capacity (Hedegaard and Münster, 2013; Patteeuw, Reynders, et al., 2015) or power storage (Kiviluoma and Meibom, 2010); (iv) more efficient operation of thermal power plants because of less need for cycling and part-load operation (Patteeuw, Henze, and Helsen, 2016; Teng, Aunedi, and Strbac, 2016); and (v) the use of existing district heating infrastructure (Böttger, Mario Götz, Theofilidi, et al., 2015; Chen et al., 2014; Henning and Palzer, 2014; D. Liu et al., 2016; Münster et al., 2012; Palzer and Henning, 2014).

For instance, Teng, Aunedi, and Strbac (2016) conclude from long-term analyses for the United Kingdom that flexible heat pumps could significantly lower the costs for integrating renewables and reducing carbon emission, particularly if heat pumps can provide frequency response. This is, among other factors, driven by improved efficiency of thermal generators due to smoother residual load and less need to run generators in part-load mode. Overall savings in renewable integration costs facilitated by flexible heat pumps are composed of lower costs for both backup and balancing (CAPEX and OPEX) and amount up to 6.5 Pound Sterling per MWh in a 2050 scenario. In an stylized Belgian setting, Patteeuw, Henze, and Helsen (2016) provide a related finding.

With different co-authors, Hedegaard, B. Mathiesen, et al. (2012) and Hedegaard and Münster (2013) simulates the Danish energy system with complementary models. Here, heat pumps and passive heat storage are found to be low-cost options for reducing renewable curtailment and fossil fuel consumption. In 2030, decentralized heat pumps could save more than 10% of system costs compared to a reference without heat pumps (Hedegaard and Münster, 2013). Yet additional active heat storage decreases overall system costs not at all (Hedegaard, B. Mathiesen, et al., 2012) or only to a minor extent (Hedegaard and Münster, 2013) as this would incur relatively large capital costs. This finding is corroborated by Patteeuw and Helsen (2016) for Belgium who find that high investment costs and losses make active thermal storage inefficient. Likewise, Papaefthymiou, Hasche, and Nabe (2012) find significant cost reductions when large-scale deployment of decentralized heat pumps in Germany is combined with passive thermal storage in the building mass. The analysis shows a growing potential for system cost savings with higher renewables penetration, indicating a future key role for the flexibility provided by passive thermal storage.

Taking on a broader perspective, Connolly, Henrik Lund, and Brian V. Mathiesen (2016) point to a general transformation of the cost structure of energy systems, that is, a shift from fuel to investment costs. Comparing scenarios with very high renewable shares up to 100% and more fossil-based reference scenarios, several analyses show that renewable-dominated systems that make use of power-to-heat may incur equal or only slightly higher total costs while achieving larger emission reductions (Connolly, Henrik Lund, and Brian V. Mathiesen, 2016; Henning and Palzer, 2014; Østergaard, Brian Vad Mathiesen, et al., 2010; Palzer and Henning, 2014). Yet external costs of fossil fuel use are often not properly considered in such analyses.

Comparative analyses on sector coupling conclude that it is first and foremost cost-effective to couple the power and heat sectors (Kiviluoma and Meibom, 2010; Brian V. Mathiesen and Henrik Lund, 2009; Schaber, Steinke, and Hamacher, 2013). Schaber, Steinke, and Hamacher (2013) argue that cost savings related to fuel consumption would be similar for coupling the power and hydrogen sectors; however, this would require higher investment costs compared to power-heat-coupling. Likewise, Brian V. Mathiesen and Henrik Lund (2009) concede that some types of electrolysers could supply larger operational flexibility than heat pumps, but are at the same time considerably less efficient and hence uneconomical. Kiviluoma and Meibom (2010) find that power-to-heat options coupled with thermal storage can be more cost-effective than the grid integration of electric vehicles – yet both options combined would be even better.

2.6.3 Integration of variable renewable electricity

To be precise, we understand "renewable energy integration" as a higher utilization of renewable energy sources to meet final energy demand. Power-to-heat can contribute to such integration with respect to both a better utilization of existing assets and additional renewable capacity expansion. In particular, power-to-heat allows making better use of temporary renewable surplus generation. This may already apply (i) without the use of additional heat storage (Patteeuw, Reynders, et al., 2015; Waite and Modi, 2014), particularly in case district heating systems can be used (Böttger, Mario Götz, Lehr, et al., 2014; Böttger, Mario Götz, Theofilidi, et al., 2015; Hedegaard and Münster, 2013; D. Liu et al., 2016; Henrik Lund, Möller, et al., 2010; Østergaard, Brian Vad Mathiesen, et al., 2010; Salpakari, Mikkola, and P. D. Lund, 2016). Utilization of renewable surpluses generally improves if (ii) additional active or passive heat storage is available (Arteconi et al., 2016; Chen et al., 2014; Connolly, Henrik Lund, and Brian V. Mathiesen, 2016; Fehrenbach et al., 2014; Kiviluoma and Meibom, 2010; Østergaard and Henrik Lund, 2011; Palzer and Henning, 2014; Papaefthymiou, Hasche, and Nabe, 2012; Patteeuw, Henze, and Helsen, 2016; Patteeuw, Reynders, et al., 2015; Pensini, Rasmussen, and Kempton, 2014; Schaber, Steinke, and Hamacher, 2013); or if (iii) flexible fuel switching facilitated by hybrid heating systems enables "virtual" energy storage (Ehrlich, Klamka, and Wolf, 2015; Heinen, Burke, and O'Malley, 2016).

Patteeuw and co-authors highlight the value of additional flexibility for renewable integration in studies for Belgium: they find substantially reduced renewable curtailment in

case of system-optimal use of decentralized heat pumps (Patteeuw and Helsen, 2016), in particular compared to inflexible heat pump use (Patteeuw, Reynders, et al., 2015). This allows reducing curtailment by around 50%; participating households, however, would have to receive appropriate incentives (Patteeuw, Henze, and Helsen, 2016).

Hedegaard and Münster (2013) bring forward that the large-scale installation of heat pumps is a key strategy for increasing the share of wind power in total Danish primary energy consumption. Investments into additional auxiliary control equipment, which would render individual heat pumps more flexible, are found to be socio-economically feasible, yet related benefits are only moderate. Further papers on Denmark apply the energy system model energyPLAN, which explicitly targets maximizing renewable energy use: Brian V. Mathiesen and Henrik Lund (2009) conclude that centralized heat pumps are by far the most suitable technology to save non-renewable primary fuels by 2030. Combined with electric boilers, centralized heat pumps help minimizing excess wind electricity. Hedegaard, B. Mathiesen, et al. (2012) derive similar conclusions for a 2020 setting with a 50% wind power share. They identify reduced excess electricity production by 8% in case of a large-scale roll-out of decentralized heat pumps. While active heat storage only moderately increases this figure, passive thermal storage in buildings reduces curtailment by up to 19%. In two studies on municipal energy systems (Østergaard and Henrik Lund, 2011; Østergaard, Brian Vad Mathiesen, et al., 2010), Østergaard analogously derives a key role for centralized heat pumps in a renewable-dominated future system.

The literature provides similar findings for other energy systems: Kiviluoma and Meibom (2010), for Finland, find that power-to-heat options with active storage lead to a higher optimal wind power capacity. Likewise, Waite and Modi (2014), for New York City, argue that a mass roll-out of individual heat pumps enables greater expansion of wind power. While the overall utilization of wind power increases, the share of wind generation to cover conventional power demand decreases. In a study for Beijing in 2020, Chen et al. (2014) determine an effective reduction of wind power curtailment through both the large-scale roll out of heat pumps and SETS. Under 20% wind penetration, passive heat storage suffices; with 40% wind, however, SETS are more effective to reduce wind curtailment due to additionally available active heat storage capacity. Also for the Beijing region, D. Liu et al. (2016) determine a reduction in wind power curtailment from 7.5% to below 2% for an optimal roll-out of centralized electric boilers. Hughes (2010) simulates the potential of SETS with different storage sizes for wind power integration in a Canadian island setting. Here, increasing numbers of SETS systems as well as increasing storage capacities of SETS reduce wind power surpluses, but may also diminish heating security due to (exogenously) limited wind power availability.

Two papers devise a framework of fully renewable electricity supply: For Helsinki, Salpakari, Mikkola, and P. D. Lund (2016) conclude on a significant reduction of excess electricity from different centralized power-to-heat options – excess decreases from 40% to about 10%; the effect of additional thermal storage would be comparatively small. Pensini, Rasmussen, and Kempton (2014) study the Pennsylvania-New Jersey-Maryland (PJM) market area in the US. Here, excess electricity could be reduced by almost 90% if decentralized resistive heaters with active storage were installed. A system with centralized

heat pumps and active thermal storage could reduce curtailment by only 50%, however at considerably lower costs.

2.6.4 Decarbonization

Power-to-heat contributes to decarbonization if the substitution of fossil fuels for heating yields greater emission reductions than a potential emissions increase due to additional electricity demand (Bayer et al., 2012, cp. also). As reduced CO_2 emissions are a corollary of a higher utilization of renewable energy sources, in principle, the same channels as laid out in Section 2.6.3 apply. Beyond that, some of the reviewed works explicitly derive figures. Specifically, *ceteris paribus* analyses that compare optimal system configurations (or paths) with and without particular power-to-heat technologies can shed light on decarbonization potentials.

For Beijing, Chen et al. (2014) conclude on significant emission reductions, around 30-40%, in a scenario where heat pumps partly displace coal boilers. Similarly, Waite and Modi (2014), for New York City, assess CO_2 reductions up to about 10% when heat pumps replace 20% of gas-fired boilers. In an analysis for Finland in 2035, Kiviluoma and Meibom (2010) conclude on a 30% emission reduction if heat pumps, electric boilers, and thermal energy storage are available compared to a baseline without these options. Likewise, studies for Belgium derive a substantial decarbonization potential for households. Here, decentralized heat pumps can save between about 10 and 75% of CO_2 emissions compared to a baseline with natural gas-fired boilers, depending on the electricity mix (Patteeuw and Helsen, 2016). Focusing on consumer behavior, it was found that emission savings are up to 7% higher if households do not behave myopically, but dispatch their heat pumps in a system-optimal way (Patteeuw, Henze, and Helsen, 2016).

Several analyses find additional decarbonization benefits related to increased power-to-heat flexibility, facilitated in particular by heat storage.[6] Patteeuw, Reynders, et al. (2015) underline that CO_2 emissions for residential heating would decrease by between 15% and 55% after replacing gas-fired boilers by heat pumps in a Belgian setting with 40% wind and PV; an additional flexible use of these heat pumps would contribute another 15% to decarbonization. Likewise, Papaefthymiou, Hasche, and Nabe (2012) determine notable CO_2 savings if a given residential heat pump fleet is operated flexibly, enabled by passive storage. In contrast, Hedegaard and Münster (2013) see only minor carbon benefits from flexible operation of power-to-heat devices. In a study for Denmark in 2030, they find about 40% lower CO_2 emissions from large-scale heat pump deployment compared to a case without heat pumps. Additional flexibility from active or passive heat storage would only add a minor 2% to this figure. A possible emission increase due to thermal losses of active heat storage is highlighted by Chen et al. (2014) who analyze the roll-out of SETS in Beijing in 2020. Analogously, Patteeuw and Helsen (2016) argue that thermal energy storage could increase CO_2 emissions of buildings due to higher energy demand arising from standby losses; for space heating, the storage capacity of the building mass would be sufficient.

[6] For emission effects of other thermal energy storage applications see Cabeza et al. (2015).

Focusing on system services, Böttger, Mario Götz, Theofilidi, et al. (2015), for Germany, determine lower CO_2 emissions, by 0.4 - 0.9%, when centralized electric boilers participate in control power supply. Teng, Aunedi, and Strbac (2016) provide a related finding for the UK: they conclude that the flexibility provided by heat pumps enables substantial CO_2 emissions reductions, up to 30%, compared to a case with non-flexible heat pumps, particularly if heat pumps can provide frequency response.

2.6.5 Power prices and electricity demand for power-to-heat

Some papers explicitly consider the impact of power-to-heat applications on electricity prices. If electricity substitutes other fuels in residential heating, demand for electric power increases (Arteconi et al., 2016; Barton, Huang, et al., 2013; Connolly, Henrik Lund, and Brian V. Mathiesen, 2016; Cooper et al., 2016; Kirkerud et al., 2014; Merkel, McKenna, et al., 2017; Patteeuw, Bruninx, Arteconi, et al., 2015; Patteeuw, Reynders, et al., 2015; Schaber, Steinke, and Hamacher, 2013), and, in turn, power prices may rise (Arteconi et al., 2016; Bauermann, Spiecker, and Weber, 2014; Kirkerud et al., 2014). However, the high efficiency of heat pumps and the flexibility of new loads may counteract this effect to some extent.

Arteconi et al. (2016) and Patteeuw, Bruninx, Arteconi, et al. (2015) explicitly address this effect in studies for Belgium, loosely calibrated to 2030 parameter projections. They conclude that the additional electricity demand for residential heat can cause substantial price spikes if inflexible, that is, if it must be served within the hour of demand. If active and passive heat storage is available for a quarter to half of this load, price spikes largely vanish, also leading to a reduced consumer bill; the additional price effect of an entirely flexible demand is rather small.

For the United Kingdom, Cooper et al. (2016) argue that peak demand, defined as the minute with highest residual load, increases substantially in case of a large-scale roll-out of heat pumps. In 2030 scenarios without thermal storage except for the building mass, heat pumps in 80% of all buildings increase peak demand by about 30%, compared to a baseline without heat pumps. However, a more moderate heat pump roll-out, their flexible operation, and both active and passive thermal storage can mitigate the increase to between 7 and 16%. Likewise, Barton, Huang, et al. (2013) state that the additional peak load from heat pump electricity demand can be significantly reduced through flexible operation.

For Germany, Bauermann, Spiecker, and Weber (2014) argue that heat pumps would only have a minor impact on power prices. Rather, they contribute to the power system's flexibility and, thus, help smoothing prices. In a counterfactual analysis for Norway, whose power system is dominated by hydro power, Kirkerud et al. (2014) come to a related conclusion: currently installed auxiliary electric boilers in district heating networks have a significant upward impact on power prices in a wet year but little impact in a dry year, where they are used only to a minor extent. Conversely, if heat pumps or electric boilers substitute fossil fuels in decentralized residential heating, price impacts in dry years would be substantial.

2.6.6 Structure of heat supply

Studies on the structure of heat supply shed light on trade-offs between power-to-heat technologies (Bach et al., 2016; Brian V. Mathiesen and Henrik Lund, 2009; Østergaard, Brian Vad Mathiesen, et al., 2010). Specifically, several analyses endogenously determine an optimal capacity mix of heating technologies (Bauermann, Spiecker, and Weber, 2014; Dodds, 2014; Fehrenbach et al., 2014; Heinen, Burke, and O'Malley, 2016; Kiviluoma and Meibom, 2010; Merkel, McKenna, et al., 2017; Münster et al., 2012; Patteeuw and Helsen, 2016; Pensini, Rasmussen, and Kempton, 2014; Petrović and Karlsson, 2016). Most papers see a future central role for heat pumps in low-carbon energy systems.

Dodds (2014) analyzes the residential heat supply in the United Kingdom until 2050 under an overall 80% decarbonization constraint. Until 2030, fossil fuel-fired boilers still dominate with 90% of the heat supply; by 2050, decentralized heat pumps prevail and supply around 60% of residential heat. Specifically, a range of boundary conditions restrict heat pump deployment below the economic optimum. These comprise consumer preferences, space requirements, the presence of existing long-lived infrastructures, and regulatory inertia favoring incumbent technologies.

Likewise, Petrović and Karlsson (2016) see a central role for ground source heat pumps in Denmark by 2050, however also constrained by the available ground area. Other analyses for different Nordic countries also include a future switch from natural gas to heat pumps and to a lesser extent to electric boilers (Kiviluoma and Meibom, 2010) for decentralized heat supply, alongside continued district heating (Münster et al., 2012). Münster et al. (ibid.) project that electric heating will have fully replaced natural gas and oil in individual heating by 2025 whereas electric heating will play only a minor role in district heating supply. In a study on the district heating system of Copenhagen in 2025, Bach et al. (2016) stress a complementarity between heat pumps and CHP plants: while the former produce heat in hours with low electricity prices, the latter, conversely, do so in high-price hours. In any case, heat pumps would replace some CHP production. Moreover, the heat pumps' full-load hours would be highest when connected to the heat distribution grid, since the lower supply temperatures compared to the transmission grid significantly increase their coefficient of performance.

For Belgium, Patteeuw and Helsen (2016) provide more differentiated results. Specifically, the optimal technology mix of decentralized heat technologies differs by house types. Especially rural and detached buildings rely on heat pumps with complementary electric resistive heaters. Active heat storage is never part of the optimal supply mix. Heinen, Burke, and O'Malley (2016), in their study for Ireland in 2030, also stress that active heat storage is deployed to a larger extent only in a setting where the heating system is based on heat pumps and resistive heating to avoid price spikes. Otherwise, a mix of heat pumps or resistive heaters with natural gas boilers (and without active storage) would achieve the same goal efficiently. Moreover, the authors explicitly analyze the substitution between fuels for heating: in a hybrid system consisting of natural gas boilers and heat pumps, the latter would contribute around 50% of heat generation in a low-natural gas-price scenario. This share increases to 70% in the high-natural gas-price scenario. In combination with

heat storages, these shares rise to 85% to 90%. In a hybrid natural gas-electric system, resistive electric heating achieves only a maximum share of 30% in heat generation. However, compared to a heating system only based on natural gas boilers , reductions in CO_2 emissions in the different hybrid systems are negligible.

Fehrenbach et al. (2014) model the development of residential heat supply for Germany until 2050. Across all scenarios, oil-based heating is phased out until 2050. Likewise, the share natural gas-fired boilers decreases. Both technologies are replaced by a renewable energy mix including heat pumps, which earn a considerable market share, especially in case of high fuel and CO_2 prices as well as ambitious renewable energy targets. Besides that, higher fuel prices favor energy efficiency measures. A more moderate fuel and CO_2 price development rather fosters the expansion of micro-CHP. In the most transformative scenario, assuming high fuel prices and decreased investment costs for heat pumps, the share of natural gas-based heat generation decreases from 46% in 2010 to 14% in 2050. In turn, heat pumps dominate heat supply with a share of 46%. In this case, the CO_2 emissions of residential heat supply decrease from around 140 million tons in 2010 to about 45 million tons in 2050. In all scenarios, heat pumps and, to a somewhat lesser extent, thermal storage also provide a significant load management potential. These findings are in line with those by Merkel, McKenna, et al. (2017) who also identify high renewable energy targets as drivers for heat pumps as well as a strong impact of CO_2 and fuel prices on micro-CHP deployment. In a scenario with ambitious energy efficiency and renewable heat targets, oil- and natural gas-based heating is nearly phased-out by 2030. Instead, heat pumps, electric boilers dominate heat supply by 2050, triggering a CO_2 emissions reduction of 98% compared to 2015. In contrast, Bauermann, Spiecker, and Weber (2014) conclude for Germany that, despite major differences in scenarios, natural gas heating systems would keep their leading market position.

2.6.7 Implications of methodology choice

Besides deriving results on the potentials of power-to-heat, several of the reviewed articles distinctly discuss model formulations (Bauermann, Spiecker, and Weber, 2014; Böttger, Mario Götz, Theofilidi, et al., 2015; Dodds, 2014; Ehrlich, Klamka, and Wolf, 2015; Georges et al., 2017; Hedegaard and Balyk, 2013; Heinen, Burke, and O'Malley, 2016; Henning and Palzer, 2014; D. Liu et al., 2016; Merkel, Fehrenbach, et al., 2014; Münster et al., 2012; Nielsen et al., 2016; Papaefthymiou, Hasche, and Nabe, 2012; Patteeuw, Bruninx, Arteconi, et al., 2015; Patteeuw, Bruninx, Delarue, et al., 2015; Patteeuw and Helsen, 2016; Patteeuw, Henze, and Helsen, 2016; Petrović and Karlsson, 2016; Salpakari, Mikkola, and P. D. Lund, 2016). Section 2.5 discusses some specific examples in more detail.

Comparing results for heat pumps either modeled with a fixed or a temperature-dependent COP does not yield unanimous conclusions: Petrović and Karlsson (2016) argue that the assumptions of a fixed COP underestimates costs and CO_2 emissions substantially, especially for air-sourced heat pumps, due to underrated electricity demand at low ambient temperatures. On the contrary, Bach et al. (2016) bring forward that the application of a variable or fixed COP for centralized heat pumps has little influence on model results.

However, it is important to distinguish for centralized heat pumps to which level of the district heating network they supply. For the distribution level, they are subject to a lower supply (i.e., sink) temperature and, thus, exhibit a substantially higher COP than heat pumps on the transmission level.

Patteeuw, Henze, and Helsen (2016) compare different approaches of modeling demand-side behavior; specifically, household incentives to use their flexible heat pumps in a system-friendly manner. They conclude that time-of-use pricing yields poor incentives for system-friendly behavior because a large fleet of heat pumps does not anticipate its impact on dispatch. If price forecasts that take into account an integrated and optimized dispatch are communicated to households, their heat pump dispatch is much more system-friendly.

2.7 Conclusions

Achieving medium- and long-term climate targets calls for decarbonization not only of electricity generation, but also of the space heating sector. At the same time, the power system integration of variable wind and solar energy sources requires additional flexibility. A flexible coupling of power and heat sectors appears to be a promising strategy to address both of these challenges. Several power-to-heat technologies are available that may contribute to both decarbonizing heat supply and, if sufficiently flexible, integrating variable renewable electricity.

The reviewed literature provides a rich set of analytical approaches how to implement power-to-heat technologies in power system and market models. Numerical findings are generally idiosyncratic to geographical contexts, time horizons, and assumptions of costs, policies, and technology availability. Yet some common findings can be synthesized. The consolidated evidence at hand suggests that power-to-heat can cost-effectively contribute to renewable energy integration. This is driven by the substitution of costly fossil fuels, reduced need for expensive peak load technology, more efficient operation of thermal plants, synergies of using existing district heating infrastructures, and a better use of invested capital from reduced renewable curtailment. In turn, lower curtailment corresponds to a better integration and higher utilization of renewable energy sources. In a dynamic perspective, additional power demand for heating can also induce a further expansion of variable renewable generation capacity. Consequently, several analyses reviewed here indicate that power-to-heat decreases overall CO_2 emissions compared to scenarios without power-to-heat options. In contrast, the effect of additional heat storage on carbon emissions is ambiguous and depends on the power plant portfolio. If power is used for heating, electricity demand and power prices *ceteris paribus* rises. This does, however, not have to result in extreme price spikes if the heating sector is sufficiently flexible, for example enabled by flexible operation of power-to-heat options or thermal storage.

A range of different power-to-heat technologies have been analyzed in the reviewed articles. Specifically, many of the articles reviewed here see a central role for heat pumps – be it decentralized or connected to district heating grids – because of their beneficial effects on system costs, renewable integration and decarbonization (compare Sections 2.6.2-2.6.4). Electric boilers are likewise identified as a relevant – and often supplementary – option. In

contrast, smart electric thermal storage (SETS) hardly plays a role in the reviewed analyses. Passive heat storage in well insulated buildings can help to tap additional low-cost flexibility potentials. Yet model formulations often appear to be rather stylized and may not take the residents' behavior properly into account. The reviewed papers do not come to unanimous conclusions of the future relevance of active heat storage technologies; most analyses conclude on a rather subordinate role.

While power-to-heat plays a major role in many articles reviewed here, it can still be considered a niche in most current markets. Heating technologies not directly based on fossil fuels globally account for around a quarter of heat end energy use, over 95% of which are based on biomass and only around 1.5% on electricity (REN 21, 2017). Global statistics on power-to-heat technologies are largely missing. For Europe, market trends indicated increasing yearly sales volumes of heat pumps (largely air-to-air) between around 500,000 and 1 million units in recent years, totaling to a European stock of around 9.5 million units in 2016 (EHPA, 2017).[7] Yet this number is still small compared to the overall stock of dwellings in Europe (Sandberg et al., 2016). As regards ground-sourced heat pumps, only around 50 GW_{th} were installed world-wide in 2014, mostly in the US, China, and Europe (J. W. Lund and Boyd, 2016). Overall, heat pumps and other power-to-heat technologies are quantitatively still a small segment – but also a growing one, in part driven by tighter regulations on building energy standards and partly also by direct support measures (REN 21, 2017). Accordingly, the power-to-heat industry would have to scale up substantially in order to achieve the high future deployment levels projected in many of the articles reviewed here.

Concerning avenues for future research, there is a growing body of evidence on the future role of power-to-heat technologies in low-carbon energy systems, but there is much scope for further insights. First, our analysis of the reviewed articles' scopes indicates that most papers focus on European case studies - complementary evidence on Asia, the Americas, and Africa, would be desirable. It would also be valuable to analyze power-to-heat options in specific settings of developing countries, where both heat and power system infrastructures are often less developed compared to most analyses reviewed here. Second, while some of the articles explicitly consider other sectors of the energy system, like mobility, broadening the scope of sector coupling could provide further insights on alternative or complementary decarbonization and flexibility potentials. Specifically, combined analyses of power-to-heat and other options referred to as *power-to-x*, for instance electrolytic hydrogen generation, may shed light on the comparative attractiveness of power-to-heat. In this context, it would further be desirable to include other, non-electric renewable heating options. Third, our methodological survey shows that most reviewed papers are based on optimization models. Future research could enrich the focus by explicitly considering behavior and incentives of involved parties, be it consumers, regulators or policymakers.

[7] When also including air conditioning devices whose primary use is cooling, the number accounts to more than 28 million units (EurObserv'ER Consortium, 2017).

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3 Modeling of combined heat and power generation in the context of increasing renewable energy penetration

Modeling of combined heat and power generation in the context of increasing renewable energy penetration

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Highlights

- Simple modeling technique and parametrization of CHP in energy system modeling.
- Advanced comparison of CHP and uncoupled power and heat generation.
- Individual analysis of various CHP types under increased penetration by renewables.
- Findings: Decreasing full load hours offset increasing fuel efficiency of CHP.

Abstract

Combined heat and power (CHP) can achieve fuel efficiencies of up to 90% and is thus considered as economically advantageous and ecologically sound compared to uncoupled power and heat generation. This advantage is exploited only if CHP plants are operated as much as possible at their optimal operation point. Increasing penetration by variable renewable energy sources and more flexible technologies challenge this optimal operation. With decreasing residual power loads the required share of power in the CHP output combination decreases and a mix of alternative technologies by uncoupled power and heat generation, power-to-heat, and storage, can become more efficient than CHP. Using a cost-minimizing investment and dispatch model individual CHP technologies are examined in stylized energy systems with increasing renewable energy penetration. Findings: whereas fuel efficiency of CHP and the share of cogenerated residual power increases, this improvement is offset by decreasing full load hours.
Keywords: CHP, sector coupling, power-to-heat, heat pumps, district heating
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3.1 Introduction

Combined heat and power (CHP) plants, also known as cogeneration plants, can achieve a significantly higher fuel efficiency of up to 90% compared to an uncoupled generation of power and heat. In various countries' energy policies, CHP is therefore considered to be an ecologically sound technology that is highly efficient at meeting power and heat demands, as it assists in the reduction of both primary energy consumption and CO_2 emissions in the supply of electricity and heat (IEA, 2009).

Unlike power, which can be transported over long distances with relatively low energy losses, heat must be generated and consumed locally to avoid major energy losses through transportation. As bivalent energy generators, CHP plants do not merely feed power into national power grids; rather, they also supply heat to local consumers. Hence, CHP technology corresponds to a form of power and heat sector coupling. CHP plants provide heat either at the point of demand, for example, at industrial production sites (Wheeley, Mago, and Luck, 2011; Yusta, Jesus, and Khodr, 2008) or by means of district heating networks in urban areas (Olsthoorn, Haghighat, and Mirzaei, 2016b). Consequently, when compared to conventional power-only plants, CHP plants reveal themselves to be more constrained in the choice of an adequate production site as they bear the additional requirement of a nearby heat sink. In other words, a heat sink must be in proximity of the energy conversion plant in order to make use of the waste heat produced by conventional power generation processes to increase fuel use efficiency.

Within energy system modeling, partial equilibrium power sector models either fully neglect the CHP function of certain plants that must cover heat demand within a system (F. Leuthold, Weigt, and Hirschhausen, 2012), or they introduce stylized must-run constraints to those CHP plants (Gerbaulet and Lorenz, 2017). However, in reality, CHP plants that provide district heating must first meet a certain heat load that is dependent on weather conditions and secondly, cope with different flexibility properties according to their type of CHP technology and their technical design configuration. There is a wide variety of state-of-the-art CHP types that differ according to the type of fuel use, the way of coupling power and heat output, marginal costs, or CO_2 emissions (AGFW, 2015). The high fuel efficiencies spanning between 70% and 90%, are often cited to highlight the benefits of CHP; yet reaching such rates of efficiency is highly dependent on certain power and heat output combinations during operation (Karl, 2012), which are not necessarily congruent with actual power and heat load demands at a given point in time in the energy system. Moreover, as energy policies in various countries aim to expand power generation by vRES, such as PV and wind power, CHP plants face additional insecurities and variability in covering the residual power loads and heat loads (Mignard, Harrison, and Pritchard, 2007). This pattern poses a number of problems that increase with the energy systems' vRES penetration. Firstly, in the short term, CHP faces not only variations in heat loads according to ambient temperatures and conventional power loads, but increasing variations in residual power loads as well, due to the further variability in the availability of renewable energies. As a result, ever-changing power and heat load combinations emerge on the demand side. This can be a challenge for CHP plants since they can have slow ramping

rates and according to their design they cannot further decrease power output at a given heat output leaving them with fixed possible output combinations. If the energy system is dominated by CHP the supply side can hardly meet the demand side's variations of residual power load without economically painful curtailment of vRES. Secondly, in the long term, the residual power loads tend to decrease with increasing capacity expansion of vRES. Therefore, the residual power and heat load combinations also change reducing the cases with high residual power shares, whereas the same heat loads must be covered. Thirdly, in addition to more flexible CHP plants or CHP plants with operational fields better fitted to the usage cases, there exists a wide variety of evolving alternative flexibility options to be considered, such as power and heat storage, as well as sector coupling technology such as power-to-heat or power-to-gas, and curtailment of vRES. Lastly, still other heat source technologies exist – for instance, GSHPs operating in combination with vRES for electricity or with highly efficient and flexible combined-cycle gas turbine (CC) plants – which comprise technology alternatives to CHP that may be more economical.

To a large extent the literature concerning CHP emphasizes on the one hand its strong economical and ecological advantage because of the high achievable fuel efficiency such that CHP has a great potential in assisting to meet many countries' energy policies (H. Lund et al., 2010; Henrik Lund, Hvelplund, et al., 2000; Rong, Hakonen, and Lahdelma, 2006; Rong and Lahdelma, 2007; Streckienė et al., 2009). On the other hand putting CHP also into the context of increasing power system penetration by vRES many authors focus at the requirement to increase the flexibility of CHP plants by means of TES tanks and analyze operational improvements (Christidis et al., 2012; Fragaki, Andersen, and Toke, 2008; Haeseldonckx et al., 2007; Nuytten et al., 2013; Pagliarini and Rainieri, 2010; Sartor and Dewallef, 2018). To the best knowledge of the author there are no statements expressing doubts concerning a definite conflict between the generation expansion of CHP and vRES in the power sector due to the inflexibility of the former and the variability of the latter. Instead the literature shows ongoing research how to optimally operate existing CHP plants (Cho et al., 2009; M. Liu et al., 2019; Y. Zhang et al., 2019) or how to dimension new CHP capacities in an energy system. For the latter Ghadimi, Kara, and Kornfeld (2014) propose for manufacturing sites using CHP an integrated methodology that combines component size and operational strategy optimization in order to fully realize the potential of energy efficiency improvements. Nami and Arabkoohsar (2019) propose an organic Rankine cycle for waste-fueled CHP plants to increase the output combination's power share and exergy efficiency. Fang and Lahdelma (2016) stress on the uncertainty of forecasts for heat demand and power prices that CHP operators face. They apply a sliding time window methodology in a partial equilibrium optimization to model this uncertainty and show the improvements in cost-effectiveness of a BP CHP plant imposed by additional TES. Since this work examines a particular case in the city of Espoo, Finland, with an inherently inflexible type of CHP plant compared to other types such as EC plants, results significantly favor TES expansion. Also Firouzmakan et al. (2019) emphasize on stochastic modeling to consider uncertainties by vRES that micro-CHP plants are facing in microgrids. Their approach incorporates storage as well as demand side management (DSM). The work by Y. Zhang et al. (2019) also addresses uncertainties arising through system penetration by vRES.

Other works putting CHP into the context of substantial wind power generation expansion consider also other flexibility alternatives such as heat-only plants and power-to-heat (Rinne and Syri, 2015; Wang et al., 2015; N. Zhang et al., 2016). For instance, Rinne and Syri (2015) examine the Finish power system with substantial amounts of inflexible nuclear power generation, substantial CHP capacities, and increasing wind power penetration. Equipped with TES they consider the growing balancing role of CHP and analyze the required TES capacity and ramping rates of CHP plants. They find that with a 24% system penetration by wind power TES capacity should be five times of current levels. This effect is substantially lower at lower wind power penetrations. Furthermore, this would reduce CO_2 emissions by another three percentage points compared to a wind power expansion without additional TES capacity, since the displacement effect by wind power on CHP is alleviated. In contrast Wang et al. (2015) analyze CHP operation in a district heating network in south Finland not focusing on system penetration by electric vRES but by solar thermal heat generation and abstain from power-to-heat. While including more short-term data for more accurate determination of TES operation and testing a special solving technique for CHP problems designed by Lahdelma and Hakonen (2003), they examine which of the three existing CHP plants with varying technical properties can be abolished since the system's current thermal capacity is over-dimensioned. Other case studies are conducted for the municipality of Visoko, Bosnia and Herzegovina, that also includes district cooling and solar thermal energy by Kazagic et al. (2019), and for the operation of biomass-fueled CHP on the Åland Islands, Finland, by Pääkkönen and Joronen (2019). N. Zhang et al. (2016) focus on the interaction of P2H and PSP as means to provide flexibility to substantial CHP capacities located in Inner West Mongolia that meets strong wind power expansion. Increased flexibility of the existing CHP plants is required here to reduce wind power curtailment. Their results indicate that electric boilers are a more cost-effective means than PSP because they can better exploit otherwise curtailed wind power and relax the operational constraints of CHP plants in winter season. In order to consider further flexibility potentials provided by other energy demand sectors, the work by Zafarani, Taher, and Shahidehpour (2020) puts CHP into the context of a multicarrier energy hub with demands for electricity, heating, gas, and electric mobility.

Considering the available literature on CHP there is a general consensus that CHP is advantageous in terms of efficiency over uncoupled power and heat generation under all circumstances. This paper elaborates a more differentiated view on that by analyzing various CHP types individually under an increasing vRES system penetration, because, as will be shown, the efficiency of CHP in operation depends on the power and heat output combination. This combination can consist of very low power shares when residual power loads decrease in the energy system. Under such circumstances and with the choice of modern and most efficient technology the uncoupled power and heat generation can become more favorable. The aim of this paper is twofold: first, to introduce the technical particularities of various CHP types and their basic parametrization in a simplified but comprehensive way to be applied in energy system models; secondly, to provide a closer and more differentiated view on the role and efficiency of CHP in systems increasingly penetrated by vRESs by juxtaposing CHP with uncoupled power and heat generation.

For this purpose, the CHP and uncoupled efficiency as a function of power and heat output combination is illustrated first, and then the four aforementioned problems are addressed in within a techno-economic linear cost-minimizing investment and dispatch model through the analysis of six stylized energy systems. Each of the six systems examines the different CHP technologies separately; specifically, their interaction with conventional power and heat generation technologies, power-to-heat, storage, and power-to-gas in their coverage of hourly power and heat loads. The systems' vRES penetration is exogenously driven step-by-step by tightening a CO_2 emissions constraint. The paper provides energy system modelers better insights on how the efficiency of various CHP types behave in the interplay with alternative power and heat generation and storage technologies when vRES penetration increases under a tightening CO_2 emission constraint.

The rest of the paper is structured as follows: Section 3.2 presents the particularities of CHP and its parametrization for energy system models. Section 3.3 outlines the applied methodology; Section 3.4 lays out the six stylized systems in more detail and the data used. The results obtained are presented in Section 3.5. Section 3.6 submits conclusions.

3.2 CHP types and their parametrization

3.2.1 CHP types

There is a wide range of different CHP configurations used in practice. Table 3.1 provides an overview of the CHP types examined in this work and classifies them according to technical characteristics. In principal, all CHP types based on conventional steam cycles are fueled by any kind of fossil fuel, biomass, waste, or fuel mixes. In contrast, CHP types based on gas turbine cycles, can be only fueled by gaseous or liquid fuels, such as gas or oil.

In terms of their operation modes, CHP technologies are generally classified into those with one degree of freedom and those with two degrees of freedom. The former is characterized by a fixed output ratio of power over heat in all power output levels, since its configuration precludes any component that allows the discarding of heat energy. Consequently, power and heat output are strictly coupled, just as in a back-pressure steam turbine (BP), for example. As such, all power generated by such technology is correctly considered to be cogenerated power. On the other hand, CHP configurations with two degrees of freedom must include some component that enables discarding of heat energy. This could be a condenser (e.g. cooling tower) in the case of a steam-cycle based plant such as an extraction-condensation steam turbine (EC) or in a combined-cycle extraction-condensation CHP (CCEC); or, in the case of a gas turbine CHP (GTCHP), a bypass chimney which offsets the heat recovery boiler. Such components in these CHP types allow for more flexibility, since they are able to vary the power output to some degree, even at a given heat output. Therefore, they operate more freely in various power and heat output combinations. However, in an EC plant heat output is achieved at the expense of some power output, which corresponds to a power loss in terms of the installed power generation capacity and the fuel consumption. Further, in a gas turbine with a heat recovery boiler

Table 3.1: Overview of CHP types.

CHP technologies	Operation characteristics: one dregree of freedom	two degrees of freedom		Fuel options	
	strictly coupled	non-coupled w/o power loss	non-coupled w/ power loss	coal/ lignite/ waste/ biomass	gas/ biogas/ oil/ liquids
BP	✓			✓	✓
EC			✓	✓	✓
CCEC			✓		✓
GTCHP		✓			✓

BP: back-pressure steam turbine, EC: extraction-condensation steam turbine,
CCEC: combined-cycle extraction-condensation CHP,
GTCHP: gas turbine CHP
Source: Own depiction based on VDI (2005) and AGFW (2015).

and bypass chimney (GTCHP), heat output does not cause any power loss, as the heat output is captured from the flue-gas that arises as a byproduct of power generation. In this case, it's the level of power output that limits the output of heat. Unlike in CHP plants with only one degree of freedom, not all power generation in such plant types is necessarily categorized as cogenerated power. Depending on the method of operation, only parts of it are cogenerated, whereas other parts are generated conventionally. The steam cycle of combined-cycles can be configured either with back-pressure or extraction-condensation steam turbines (CCBP or CCEC, respectively).

3.2.2 Parametrization

Figure 3.1 illustrates the two types of operation freedoms and their most significant parameters. A BP plant is characterized by its fixed ratio, σ, of power, P, and heat, $\dot{Q}$, output which is defined by equation (3.1). This characterization implies that only those combinations of power and heat outputs are possible as described by the red line $\overline{AB}$ in Figure 3.1, also known as back-pressure line, with σ as its slope. The fuel consumption, $\dot{F}$, at each operation point, is important to determine the variable costs of power and heat joint production, and is defined by equation (3.2). Total fuel efficiency $\overline{\eta}$ is valid along the entire back-pressure line $\overline{AB}$, when abstracted from part-load efficiency. Hence, the most important parameters to give to such a plant within a model are the maximum power output $\overline{P}$, σ, and $\overline{\eta}$.

$$\sigma := \frac{P}{\dot{Q}} = \frac{\overline{P}}{\overline{Q}} \tag{3.1}$$

$$\dot{F} := \frac{P + \dot{Q}}{\overline{\eta}} = \frac{P \cdot \left(1 + \frac{1}{\sigma}\right)}{\overline{\eta}} \tag{3.2}$$

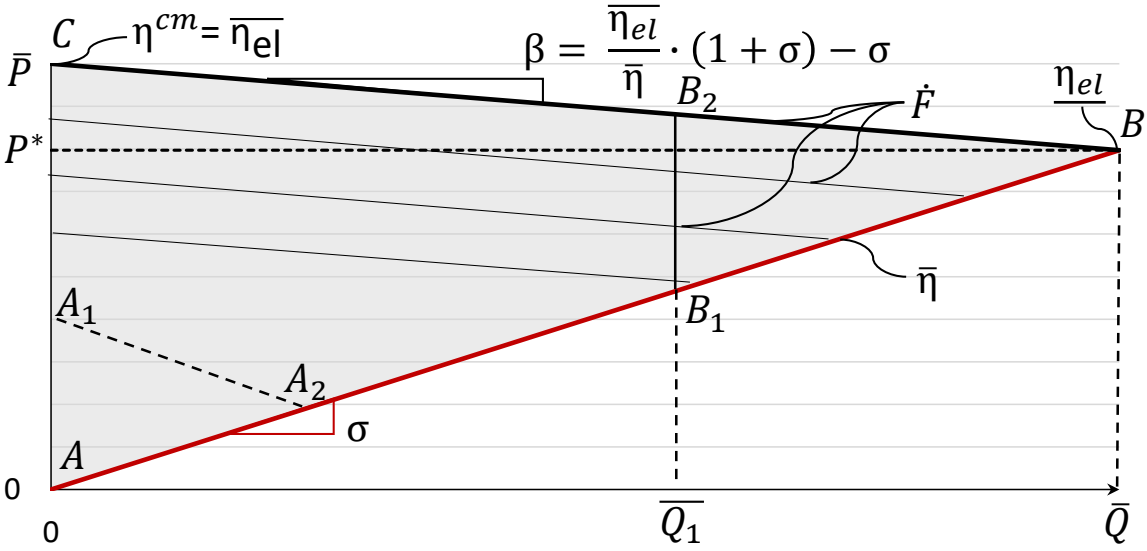


Figure 3.1: CHP operation field and its determining parameters.

β: power loss coefficient, η^{cm}: condensation mode efficiency, $\overline{\eta}$: total fuel efficiency, $\overline{\eta_{el}}$: maximum electric efficiency, $\underline{\eta_{el}}$: minimum electric efficiency, σ: power-over-heat-ratio, $\overline{P}$: maximum power output, P^*: maximum power output at maximum heat output, $\overline{Q}$: maximum heat output

Source: Own depiction based on VDI (2005).

An EC plant can also include additional power and heat output combinations to only those found on the back-pressure line. For this CHP type, the red line $\overline{AB}$ represents only a lower bound. Only the amount of power on this line at a given heat output level can be considered as coupled power. Any additional amount of power output is non-coupled. The black line $\overline{CB}$ in Figure 3.1 with its negative slope β represents the upper bound. All power and heat output combinations within the gray triangle ABC are possible. However, the total fuel efficiency, which is necessary in determining the variable costs of any output combination, differs at each operation point and equals the pre-determined maximum total fuel efficiency $\overline{\eta}$ only on the back-pressure line. Therefore, an additional parameter is required to determine a CHP type with two degrees of freedom. The efficiency parameter η^{cm} refers to the efficiency reached when the CHP plant operates fully in condensation mode (CM) , i.e. when it is not producing any heat and is functioning as a conventional power-only plant. Abstracted from part-load efficiency, η^{cm} is valid at each operation point along the line $\overline{AC}$.

The more heat energy is decoupled from the power generation process with the aim of increasing the CHP plant's heat output, the more its electrical efficiency, η_{el}, decreases. Hence, moving the operation point along line $\overline{CB}$, the electrical efficiency (starting from its maximum $\overline{\eta_{el}}$, which equals the condensation mode η^{cm}), decreases until it reaches its

minimum $\underline{\eta_{el}}$ on the back-pressure line. In contrast, since thermal efficiency, η_{th}, increases more rapidly than the electrical efficiency decreases, the total efficiency ($\eta = \eta_{el} + \eta_{th}$) increases until it reaches its maximum, $\overline{\eta}$, on the back-pressure line. Consequently, in order to fully represent such a type of CHP plant, the parameters $\overline{P}$, σ, $\overline{\eta}$, and $\overline{\eta_{el}}$ must be determined. The power loss parameter β is the upper bound's slope and is implicitly determined since the relation (3.3) must hold. Fuel consumption is determined by equation (3.4).

$$\beta := \frac{\overline{\eta_{el}}}{\overline{\eta}} \cdot (1 + \sigma) - \sigma \tag{3.3}$$

$$\dot{F} := \frac{P + \beta \cdot \dot{Q}}{\overline{\eta_{el}}} \tag{3.4}$$

Expressing the power output as a function of heat output reveals the constraint (3.5) for CHP plants with only one degree of freedom and the constraints (3.6a) and (3.6b) for those with two degrees of freedom.

$$P = \sigma \cdot \dot{Q} \tag{3.5}$$

$$P \geq \sigma \cdot \dot{Q} \tag{3.6a}$$

$$P \leq \overline{P} - \beta \cdot \dot{Q} \tag{3.6b}$$

Constraint (3.6b) illustrates the power loss necessarily occurs at a certain fuel input level when decoupling heat. If the plant operates, for instance, at point C, it generates power at its maximum capacity, yet it operates at the lowest fuel efficiency, since all fuel consumption is allocated to power generation. In contrast, if operating at point B, the plant consumes as much fuel as at point C, but functions with the highest fuel efficiency, since some of the fuel's energy is allocated to heat output. This operation method functions at the expense of some power output which is represented by the length $\overline{\overline{P}P^*}$. P^* represents here the maximum power output level at maximum heat output. The upper bound $\overline{CB}$ can also be interpreted as an iso-fuel consumption line, because all power and heat output combinations on this line require the same fuel input and, hence, bear the same variable costs.

In the case of a GTCHP that can freely choose to stream its flue-gas either through a heat recovery boiler or through a bypass chimney, there is no power loss. Harnessing the heat energy from the flue-gas or discarding it has no influence on the gas turbine's operation. Therefore, the power loss factor β always equals zero, which implies that a CHP plant with two degrees of freedom and zero power loss would have an operational field in the shape of the triangle ABP^*. This analysis leads to another implication for this type of CHP plants: by setting β to zero, equation (3.3) can be transformed into (3.7), revealing a relationship between the remaining parameters that describes a gas turbine

with heat recovery boiler (GTCHP).

$$\overline{\eta} = \overline{\eta_{el}} \cdot \left(1 + \frac{1}{\sigma}\right) \tag{3.7}$$

The theoretical maximum heat output can be expressed depending on the maximum power capacity by relation (3.8). According to Kunz et al. (2017), however, the maximum heat capacity of CHP plants with two degrees of freedom is, in reality, often smaller than what is theoretically possible, which is expressed here by the reduction factor $f = [0; 1]$ in equation (3.9). This leads to the rather trapezoidal operation area AB_1B_2C in Figure 3.1.

$$\overline{Q} = \frac{\overline{P}}{\sigma + \beta} \tag{3.8}$$

$$\overline{Q_1} = f \cdot \overline{Q} \tag{3.9}$$

Furthermore, in reality, the steam generator of any steam-cycle plant must have a minimum production level, such that an operational field of the shape $A_1A_2B_1B_2C$ would be most accurate (VDI, 2005). Nevertheless, including an output of zero leads to a non-convex solution space, which can cause computational challenges in modeling.

3.2.3 Total fuel efficiency CHP and uncoupled power and heat generation

The most common argument justifying the use and political promotion of CHP is often supported by an illustration that resembles Figure 3.2. It compares the energy input/output relation of a CHP plant to that of the uncoupled generation by a conventional power plant and a heat-only plant. According to this illustration, a CHP plant can achieve a substantial total efficiency of 85% by generating 50 units of usable heat energy and 35 units of electricity from 100 units of fuel input. In contrast, the uncoupled generation of power and heat would achieve only a total fuel efficiency of 57% with similar outputs.

However, this simplistic explanation casts CHP in a better light, in that the alternative technologies for uncoupled generation that are compared with the CHP plant have a similar electrical efficiency to that of the CHP plant, and have rather vintage heating technologies with naturally lower efficiencies. In reality, a CHP plant would have both a lower electrical and thermal efficiency compared to each of the most recent uncoupled technologies that would be installed today. Considering an EC plant, for example, such a high share of heat output in the power and heat output combination can only function at the most efficient operation points on the back-pressure line as demonstrated in the section above. This mode comes at the cost of a reduction in electrical efficiency of the CHP plant compared to a similar efficient power-only capacity as indicated by $\Delta\eta_{el}$ in Figure 3.2. Concerning thermal efficiency, since the heat energy transport medium is not heated directly as in a heat-only plant, but rather indirectly by the steam cycle in the CHP plant, thermal efficiency must naturally be lower due to increased losses in escalated heat exchange processes.

Generally, assuming similar boiler efficiencies exist in every energy conversion plant, the

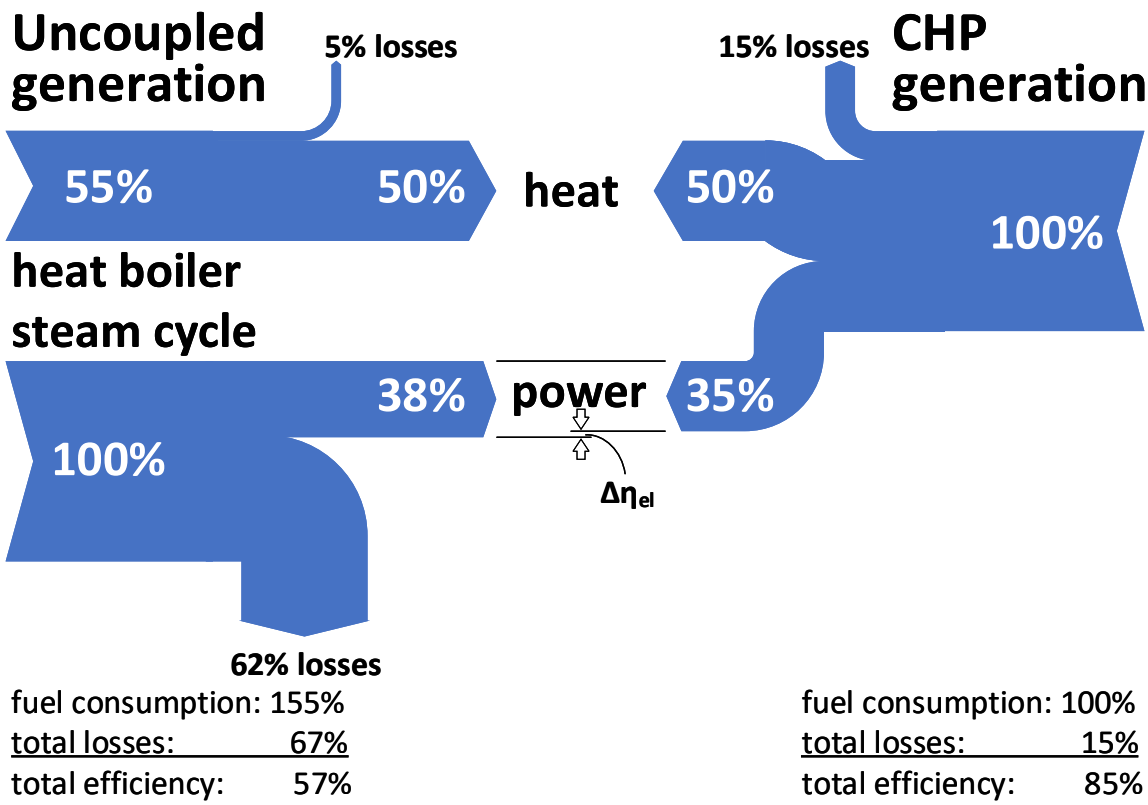


Figure 3.2: Fuel efficiency of CHP versus uncoupled generation.

Source: Own depiction based on Karl (2012).

fuel exploitation is always highest, when producing only heat. Yet, if the heat generated in a steam boiler or combustion chamber is used for power generation, there are always additional losses due to thermodynamic reasons. In a CHP plant, the fuel energy is exploited by distributing the flue-gas' exergy to either power or heat generation. The more exergy is used for power generation, the more the thermal efficiency will decrease. Contrary to this, the more of the flue-gas' exergy is allocated to heat generation, the more electrical efficiency will decrease. Hence, CHP plants always face a trade-off that necessarily leads to a reduction in its total efficiency in comparison to pure heat generation. Consequently, fuel exploitation is not always higher in a CHP plant than in uncoupled generation of power and heat. The degree of fuel efficiency in CHP and uncoupled generation depends on the power and heat output combination, which is illustrated in the following subsection.

3.2.4 Fuel efficiency as function of the power share in CHP and uncoupled generation

In order to express the total fuel efficiency of CHP and uncoupled operations as a function of power and heat output combinations, it is helpful to introduce the power share and use it to reformulate the definition of total efficiency for CHP plants and uncoupled generation. Formula (3.10) defines the power share x of the output combination. Using this and the definition for electrical efficiency (3.11) the definition of total efficiency of a CHP plant can be altered according to (3.12).

$$x := \frac{P}{P + \dot{Q}} \tag{3.10}$$

$$\eta_{el}^{CHP} := \frac{P}{\dot{F}} \tag{3.11}$$

$$\eta^{CHP} := \frac{P + \dot{Q}}{\dot{F}} = \frac{\frac{P}{x}}{\frac{P}{\eta_{el}^{CHP}}} = \frac{P}{x} \cdot \frac{\eta_{el}^{CHP}}{P} = \frac{\eta_{el}^{CHP}}{x} \tag{3.12}$$

For the purpose of comparison with CHP generation, uncoupled power and heat generation are conceptually merged into one system. Using the definition of electrical efficiency of the power-only generation, (3.13), and the thermal efficiency of the heat generation, (3.14), the total efficiency of this joint system can be expressed as a function of the power share x as depicted by definition (3.15).

$$\eta_{el}^{unc} := \frac{P}{\dot{F}_{el}} \tag{3.13}$$

$$\eta_{th}^{unc} := \frac{\dot{Q}}{\dot{F}_{th}} \tag{3.14}$$

$$\eta^{unc} := \frac{P + \dot{Q}}{\dot{F}_{el} + \dot{F}_{th}} = \frac{\frac{P}{x}}{\frac{P}{\eta_{el}^{unc}} + \frac{P \cdot \frac{1-x}{x}}{\eta_{th}^{unc}}} = \frac{\eta_{el}^{unc} \cdot \eta_{th}^{unc}}{x \cdot \eta_{th}^{unc} + (1-x) \cdot \eta_{el}^{unc}} \tag{3.15}$$

Applying some technologies' parameters as listed in Table 3.2 on the definitions (3.12) and (3.15), total efficiency of these technologies can be presented as a function of the power share as shown in Figure 3.3. Table 3.2 also indicates the possible operation range of the respective technology through the minimum and maximum power share. Introducing the definition of the power-over-heat-ratio (3.1), expression (3.16) indicates that there is a strictly linked relation between the back-pressure line and the minimum power share $\underline{x}$: the lower the σ (the flatter the back-pressure line), the lower the reachable power share x.

$$\underline{x} := \frac{P}{P + \dot{Q}} = \frac{\sigma \cdot \dot{Q}}{\sigma \cdot \dot{Q} + \dot{Q}} = \frac{\sigma}{1 + \sigma} \tag{3.16}$$

Figure 3.3 illustrates that total fuel efficiency of all CHP technologies with two degrees of freedom increases from the level of their pure electrical efficiency at a power share of

Table 3.2: Parameters for comparison of CHP versus uncoupled generation.

Technology	$\overline{\eta}$	$\overline{\eta_{el}}$	$\overline{\eta_{th}}$	σ	β	$\underline{x}$	$\overline{x}$
BP	90%			0.3–0.6		0.23–0.39	0.23–0.39
EC	75%	40%		0.8	0.16	0.44	1
CCEC	75%	52%		1.5	0.23	0.6	1
GTCHP	85%	35%		0.7	0	0.41	1
ST		40%					
CC		52%					
DHB			105%				

BP: back-pressure steam turbine,EC: extraction-condensation steam turbine, CCEC: combined-cycle extraction-condensation CHP, GTCHP: gas turbine CHP, ST: steam turbine, CC: combined-cycle gas turbine, DHB: district heating boiler
Source: Own depiction based on UBA (2018).

100% up to their maximum total fuel efficiency when decreasing the power share. When the power share is decreased further on the demand side, this maximum fuel efficiency can be maintained only by reducing the overall power and heat output level. The uncoupled generation is represented here in two forms: a coal-fueled steam turbine (ST) and a gas-fueled combined-cycle gas turbine (CC) plant dedicated to power generation, each in combination with a gas-fueled heat boiler (DHB) dedicated to heat generation. Modern heat-only plants also exploit the condensation energy of the steam mixed in the flue-gas, which enables them to reach thermal efficiencies of 105% (greater 100% due to reference to the lower caloric value). For both uncoupled generation combinations, total fuel efficiency continuously increases with a decrease in power share. The BP CHP plant maintains the same fuel efficiency and is represented only by dots for various σ-values instead of by a line, indicating that it can serve only certain power share points depending on the corresponding σ-value. Thus, this seemingly high fuel efficiency comes at the cost of very low flexibility.

Among the CHP technologies with two degrees of freedom and given the parameters chosen in Table 3.2, the CCEC plant always demonstrates the highest rates of fuel efficiency compared to the EC and GTCHP plants at high power shares, due to its significantly higher electric efficiency. When the power share further decreases, the GTCHP plant can achieve a higher fuel efficiency. Figure 3.3 compares the uncoupled power and heat generation completely based on gas (uncoupled CC+THB) with the three CHP technologies with two degrees of freedom, revealing indeed power share ranges for each of them, in which the uncoupled generation can achieve a higher fuel efficiency than CHP generation. This dependence of the fuel efficiency as a function of the power share in the output combination is neglected in the commonly used illustration in Figure 3.2.

On the demand side, the power share is constantly changing according to the conventional power load and the heat load in district heating, which is in turn determined by ambient temperature variations. On the one hand, assuming that vRES are primarily used to cover conventional power load, the residual power share decreases as the height of the availability

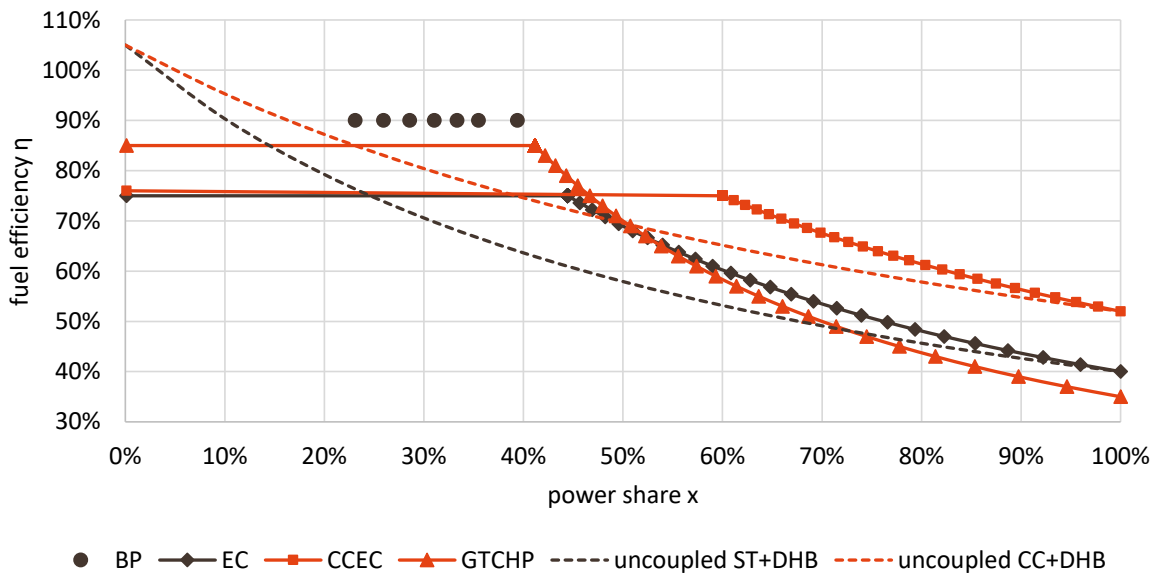


Figure 3.3: Fuel efficiency of CHP and uncoupled power and heat generation as a function of the power share.

Source: Own depiction inspired by Karl (2012).

of vRES increases. Within energy systems with increasing vRES capacity expansion, CHP plants are more frequently forced to contend with very low residual power shares. On the other hand, the more alternative heating technologies are used, such as DHBs or power-to-heat, the more the residual power share increases. Therefore, the performance of each of the most significant types of CHP technologies in terms of fuel efficiency and full load hours in the context of increasing vRES penetration shall be examined in the following.

3.3 Model formulation

In order to simulate the various CHP technologies' performance and their interaction with other power and heat generation technology, a static techno-economic linear optimization model is employed as formulated in this section and implemented in GAMS for solving with Cplex (GAMS, 2018; IBM, 2019). All variables are written in capital letters and parameters in lower-case letters. All symbols are listed in a nomenclature at the very end.

3.3.1 Objective function

The model minimizes total annualized costs consisting of investment, fixed operation and maintenance costs (fixed O&M) and operating costs over one year, according to (3.17). Equations (3.18a) to (3.18c) describe these cost components in more detail. Section 3.4.3 explains in detail how the cost factors $c_{i,f}^{inv}$, $c_{i,f}^{fom}$, $c_{i,f}^{inv}$, and $c_{i,f}^{var}$ are determined. Operating

costs over the entire year are composed of variable costs and ramping costs.

$$TC = IC + FO\&MC + OC \tag{3.17}$$

$$IC = \sum_f \left(\sum_{i \in \mathcal{P}} c_{i,f}^{inv} \cdot \overline{G}_{i,f} + \sum_{i \in \mathcal{H}} c_{i,f}^{inv} \cdot \overline{Q}_{i,f} + \sum_{i \in \mathcal{S}} c_{i,f}^{invST} \cdot \overline{S}_{i,f} \right) \tag{3.18a}$$

$$FO\&MC = \sum_f \left(\sum_{i \in \mathcal{P}} c_{i,f}^{fom} \cdot \overline{G}_{i,f} + \sum_{i \in \mathcal{H}} c_{i,f}^{fom} \cdot \overline{Q}_{i,f} \right) \tag{3.18b}$$

$$OC = \sum_f \sum_i \left(c_{i,f}^{var} \cdot \sum_t FC_{i,f,t} + c_{i,f}^{ramp} \cdot \sum_t \left(G_{i,f}^{up} + G_{i,f}^{dn} \right) \right) \tag{3.18c}$$

The fuel consumption required to compute operating costs in equation (3.18c) is respectively calculated for various technologies as outlined by (3.19).

$$FC_{i,f,t} = \frac{G_{i,f,t}}{\eta_{i,f}} \qquad \forall\ i \in \mathcal{CP}, f, t \tag{3.19a}$$

$$FC_{i,f,t} = \frac{G_{i,f,t} + Q_{i,f,t}}{\eta_{i,f}} \qquad \forall\ i \in \mathcal{CHP}^{\mathcal{BP}}, f, t \tag{3.19b}$$

$$FC_{i,f,t} = \frac{G_{i,f,t} + \beta_{i,f} \cdot Q_{i,f,t}}{\eta_{i,f}^{cm}} \qquad \forall\ i \in \mathcal{CHP}^{\mathcal{EC}}, f, t \tag{3.19c}$$

$$FC_{i,f,t} = \frac{Q_{i,f,t}}{\eta_{i,f}} \qquad \forall\ i \in \mathcal{H}, f, t \tag{3.19d}$$

3.3.2 Power and heat balance

The main requirement in the energy system is for power and heat loads to be continuously covered in the short term, as formulated in the power balance (3.20) and heat balance (3.21). The total hourly power load consists of the conventional power load and load caused by power-to-heat, power-to-gas, and by power storage charging; it is balanced by any power generating technology or power storage discharge. Analogously, total hourly heat load, which consists of the sum for space heating and domestic hot water demand, and heat storage charging are balanced by all heat generating technologies and heat storage discharge.

$$p_t + D_t^{P2H} + D_t^{P2G} + PS_t^C = \sum_f \sum_{i \in \mathcal{P}} G_{i,f,t} + \eta_{i,f} \cdot PS_t^D \qquad \forall\ t \tag{3.20}$$

$$q_t + HS_t^C = \sum_f \left(\sum_{i \in \mathcal{CHP} \cup \mathcal{H}} Q_{i,f,t} + \sum_{i \in \mathcal{P}2\mathcal{H}} \eta_{i,f} \cdot G_{i,f,t} \right) + HS_t^D \qquad \forall\ t \tag{3.21}$$

3.3.3 Constraints

All technologies are subject to some constraints. Capacities for vRES can only generate power up to their maximum hourly capacity factor, which is determined by the intensity of wind or solar radiation for wind power or PV, respectively, as illustrated by equation (3.22). The difference between the hourly potential and the actual power generation is considered to be a curtailment, $C^{vRES}_{i,f,t}$. Constraints (3.23) and (3.24) limit all power generation as well as power input into power-to-heat technology and heat generation, respectively, to the installed capacity. Power output of BP CHP is farther restricted by the fixed power-over-heat-ratio σ according to (3.25) and the operational field of EC CHP by the lower and upper bound (3.26) and (3.27), respectively. This latter constraint implies that the maximum heat output capacity of CHP plants is linked to their maximum power capacity, according to (3.28). Equation (3.29) links the power input for power-to-heat technology to the power balance (3.20) causing implicit variable costs.

$$G_{i,f,t} + C^{vRES}_{i,f,t} = cf_{i,f,t} \cdot \overline{G}_{i,f} \qquad \forall\ i \in v\mathcal{RES}, f, t \tag{3.22}$$

$$G_{i,f,t} \leq \overline{G}_{i,f} \qquad \forall\ i \in \mathcal{P}\ \cup\ \mathcal{P}2\mathcal{H}, f, t \tag{3.23}$$

$$Q_{i,f,t} \leq \overline{Q}_{i,f} \qquad \forall\ i \in \mathcal{H}, f, t \tag{3.24}$$

$$G_{i,f,t} = \sigma_{i,f} \cdot Q_{i,f,t} \qquad \forall\ i \in \mathcal{CHP}^{\mathcal{BP}}, f, t \tag{3.25}$$

$$G_{i,f,t} \geq \sigma_{i,f} \cdot Q_{i,f,t} \qquad \forall\ i \in \mathcal{CHP}^{\mathcal{EC}}, f, t \tag{3.26}$$

$$G_{i,f,t} \leq \overline{G}_{i,f} - \beta_{i,f} \cdot Q_{i,f,t} \qquad \forall\ i \in \mathcal{CHP}^{\mathcal{EC}}, f, t \tag{3.27}$$

$$\overline{Q}_{i,f} \leq \frac{\overline{G}_{i,f}}{\sigma_{i,f} + \beta_{i,f}} \qquad \forall\ i \in \mathcal{CHP}, f \tag{3.28}$$

$$D^{P2H}_t = \sum_f \sum_{i \in \mathcal{P}2\mathcal{H}} G_{i,f,t} \qquad \forall\ t \tag{3.29}$$

3.3.4 Ramping

All coal-fueled power generation technology is restricted by a limited load change velocity as expressed by (3.30).

$$G^{up}_{i,f,t} \leq r^{up}_{i,f} \cdot \overline{G}_{i,f} \qquad \forall\ i \in \mathcal{P} \cup \mathcal{CHP}, f, t \tag{3.30a}$$

$$G^{dn}_{i,f,t} \leq r^{dn}_{i,f} \cdot \overline{G}_{i,f} \qquad \forall\ i \in \mathcal{P} \cup \mathcal{CHP}, f, t \tag{3.30b}$$

$$G_{i,f,t} - G_{i,f,t-1} = G^{up}_{i,f,t} - G^{dn}_{i,f,t} \qquad \forall\ i \in \mathcal{P} \cup \mathcal{CHP}, f, t \tag{3.30c}$$

3.3.5 Power storage

Power storage by batteries is restricted in two ways. The charging and discharging capacity is limited by constraints (3.31a) and (3.31b), respectively. The actual energy storage vol-

ume comprises an additional restriction (3.31c). Efficiency losses of power storage activity appear during charging (3.31d) and discharging (3.20).

$$PS_t^C \leq \overline{G}_{i,f} \qquad \forall\ i \in \mathcal{P} \cap \mathcal{S}, f, t \tag{3.31a}$$
$$PS_t^D \leq \overline{G}_{i,f} \qquad \forall\ i \in \mathcal{P} \cap \mathcal{S}, f, t \tag{3.31b}$$
$$PS_t^L \leq \overline{S}_{i,f} \qquad \forall\ i \in \mathcal{P} \cap \mathcal{S}, f, t \tag{3.31c}$$
$$PS_t^L = PS_{t-1}^L + \eta_{i,f} \cdot PS_t^C - PS_t^D \qquad \forall\ i \in \mathcal{P} \cap \mathcal{S}, f, t \tag{3.31d}$$

3.3.6 Thermal energy storage

Heat storage is modeled analogously to power storage. The only difference here is that efficiency losses do not appear during charging and discharging activity, but as stand-by losses in the heat storage balance (3.32d).

$$HS_t^C \leq \overline{Q}_{i,f} \qquad \forall\ i \in \mathcal{H} \cap \mathcal{S}, f, t \tag{3.32a}$$
$$HS_t^D \leq \overline{Q}_{i,f} \qquad \forall\ i \in \mathcal{H} \cap \mathcal{S}, f, t \tag{3.32b}$$
$$HS_t^L \leq \overline{S}_{i,f} \qquad \forall\ i \in \mathcal{H} \cap \mathcal{S}, f, t \tag{3.32c}$$
$$HS_t^L = \eta_{i,f} \cdot HS_{t-1}^L + HS_t^C - HS_t^D \qquad \forall\ i \in \mathcal{H} \cap \mathcal{S}, f, t \tag{3.32d}$$

3.3.7 Power-to-gas

One method by which to make use of power surpluses in the long term is by means of power-to-gas technology, as modeled according to (3.33). Since there is effectively no limit on energy storage volume, no such restriction is implemented, unlike the case of power or heat storage. There are only efficiency losses whilst charging (3.33b), which is further restricted by an installed capacity (3.33c). It is assumed here that power-to-gas consists only of hydrogen production without further methanization, which leads to a relatively high conversion efficiency of 70%.

$$SG_t^L = SG_{t-1}^L + SG_t^C - SG_t^D \qquad \forall\ t \tag{3.33a}$$
$$SG_t^C = \eta_{i,f} \cdot D_t^{P2G} \qquad \forall\ i \in \mathcal{P}2\mathcal{G}, f, t \tag{3.33b}$$
$$D_t^{P2G} \leq \overline{G}_{i,f} \qquad \forall\ i \in \mathcal{P}2\mathcal{G}, f, t \tag{3.33c}$$

Discharging occurs when synthetic gas is consumed in any gas-fueled technology, such as in a GT, CC, gas-fueled CHP plant, or heat-only plant. Hence, the fuel consumption of

these technologies is modified according to equations (3.19a mod) to (3.19d mod).

$$FC_{i,f,t} + SG^{D}_{i,f,t} = \frac{G_{i,f,t}}{\eta_{i,f}} \qquad \forall\ i \in \mathcal{CP}, f \mathrel{\hat{=}} gas, t \qquad (3.19a\ mod)$$

$$FC_{i,f,t} + SG^{D}_{i,f,t} = \frac{G_{i,f,t} + Q_{i,f,t}}{\eta_{i,f}} \qquad \forall\ i \in \mathcal{CHP}^{\mathcal{BP}}, f \mathrel{\hat{=}} gas, t \qquad (3.19b\ mod)$$

$$FC_{i,f,t} + SG^{D}_{i,f,t} = \frac{G_{i,f,t} + \beta_{i,f} \cdot Q_{i,f,t}}{\eta^{cm}_{i,f}} \qquad \forall\ i \in \mathcal{CHP}^{\mathcal{EC}}, f \mathrel{\hat{=}} gas, t \qquad (3.19c\ mod)$$

$$FC_{i,f,t} + SG^{D}_{i,f,t} = \frac{Q_{i,f,t}}{\eta_{i,f}} \qquad \forall\ i \in \mathcal{H}, f \mathrel{\hat{=}} gas, t \qquad (3.19d\ mod)$$

3.4 Energy systems and data

3.4.1 Energy systems under investigation

Table 3.3 lists the six energy system examined here and the available technologies for the optimization model of each of the six. In five of these systems, only one single CHP technology is available for the optimization model in order to analyze it individually. Additionally, in each of the five systems, only one single conventional power generation technology and gas-fueled DHBs dedicated to covering heat loads are available as alternative uncoupled generation to CHP. This permits an analysis of the performance and interaction with other technologies of each CHP type separately. In the mix system, the sixth, all CHP and conventional power generation technologies are applicable to the model.

First, at 0% vRES penetration in the system, the respective CHP technology under examination and the alternative uncoupled power and heat generation capacities are endogenously dimensioned by the model on a greenfield to cover hourly exogenous power and heat loads, minimizing total costs without further constraints. Then, these capacities are maintained and an exogenous CO_2 emissions constraint is tightened step-by-step in order to increase vRES penetration in the system by ten percentage points from 0% to nearly 100%. For each of the six systems, this CO_2 cap is calibrated in such a way that it leads to a vRES penetration of exactly 10%, 20%, etc.; that is, for instance, 10% of total yearly demand for conventional power, power-to-heat, and power-to-gas. The model determines the capacity mix of PV, onshore and offshore wind endogenously. In all vRES penetrations higher than 0%, the model can furthermore endogenously invest into power-to-heat and various storage technologies. This concept allows for an exploration of how the optimal setup of CHP and uncoupled conventional power and heat generation adapts to increasing vRES penetration and auxiliary technologies that increase flexibility.

3.4.2 Power and heat demand

The hourly conventional power and heat demand to be covered in the model is a stylized data set taken from real data from the city of Berlin, Germany, in the year 2015. Total

Table 3.3: Energy systems under examination.

System			BP+ST	BP+CC	EC+ST	EC+CC	CCEC+CC	mix
at 0% vRES	endogenous	**CHP**	BP	BP	EC	EC	CCEC	all CHP, GTCHP
		power	ST	CC	ST	CC	CC	ST, CC, GT
		heat	DHB	DHB	DHB	DHB	DHB	DHB
at 10% – 100% vRES	exogenous	**CHP power heat**	as in 0% vRES	as in 0% vRES	as in 0% vRES	as in 0% vRES	as in 0% vRES	as in 0% vRES
	endogenous	**P2H**	GSHP, DHEB	GSHP, DHEB	GSHP, DHEB	GSHP, DHEB	GSHP, DHEB	GSHP, DHEB
		storage	TES, BT, P2G	TES, BT, P2G	TES, BT, P2G	TES, BT, P2G	TES, BT, P2G	TES, BT, P2G

GSHP: ground source heat pump, DHEB: district heating electrode boiler,
TES: thermal energy storage, BT: battery, P2G: power-to-gas

yearly demands for power and heat supplied by district heating are found in the statistical energy reports of Berlin (AfS BB, 2017). In that year, the net electricity demand amounted to 13.4 $\mathrm{TWh_{el}}$ and the net district heating demand to 10.4 $\mathrm{TWh_{th}}$. Power load variations are taken from the 50Hertz transmission control area (50Hertz, 2015). The heat load consists of a major demand for space heating and a minor demand for domestic hot water energy. The latter amounts to 16% of total yearly net district heating demand. Whereas space heating demand depends on ambient temperature and exists only during the heating season, domestic hot water demand follows an hourly standard profile throughout the year taken from Frederiksen and Werner (2014). Therefore, the demand profile of total hourly heat demand drops drastically during the non-heating season. The hourly space heating load can be derived from the hourly Berlin ambient temperature provided by the German Meteorological Service (DWD, 2017) and from the concept of heating degree hours with a threshold temperature of 15°C. Finally, the power and heat loads are scaled in such a way that the actual maximum power load equals 100 $\mathrm{MW_{el}}$ whereas all other proportions are maintained. Due to the stylized nature of the data used, units are omitted in the results. The nomenclature lists units only for a better understanding of the analysis as a whole.

3.4.3 Technologies

Table B.2 in B.2 lists all available technologies with their assumed economic and technical characteristics. From these data, annual investment and fixed O&M costs can be derived, according to equations (3.35) to (3.38). To compute the annuity factor, an interest rate of $ir = 8\%$ is assumed. Additionally, Table 3.4 lists the fuel costs to be used to compute variable costs according to (3.39) and carbon content.

$$a_{i,f} = \frac{ir \cdot (1+ir)^{elt_{i,f}})}{(1+ir)^{elt_{i,f}} - 1} \qquad \forall\, i, f, t \tag{3.35}$$

$$c_{i,f}^{inv} = a_{i,f} \cdot Investment_cost_{i,f}\ [\text{€/kW}] \cdot 1,000 \qquad \forall\, i, f, t \tag{3.36}$$

$$c_{i,f}^{inv\ ST} = a_{i,f} \cdot Investment_cost_sto_{i,f}\ [\text{€/kWh}] \cdot 1,000 \qquad \forall\, i \in \mathcal{S}, f, t \tag{3.37}$$

$$c_{i,f}^{fom} = fixed_O\&M_cost_{i,f}\ [\text{€/kW}] \cdot 1,000 \qquad \forall\, i, f, t \tag{3.38}$$

$$c_{i,f}^{var} = \begin{cases} fp_f + \eta_{i,f} \cdot c_{i,f}^{var\ O\&M} & \text{, if } i \notin \mathcal{CHP}^{\mathcal{EC}} \\ fp_f + \eta_{i,f}^{cm} \cdot c_{i,f}^{var\ O\&M} & \text{, if } i \in \mathcal{CHP}^{\mathcal{EC}} \end{cases} \tag{3.39}$$

Table 3.4: Fuel prices and carbon content.

Fuel	Price €/MWh	Carbon content t_{CO_2}/MWh
coal	6.6	0.337
gas	15.0	0.201

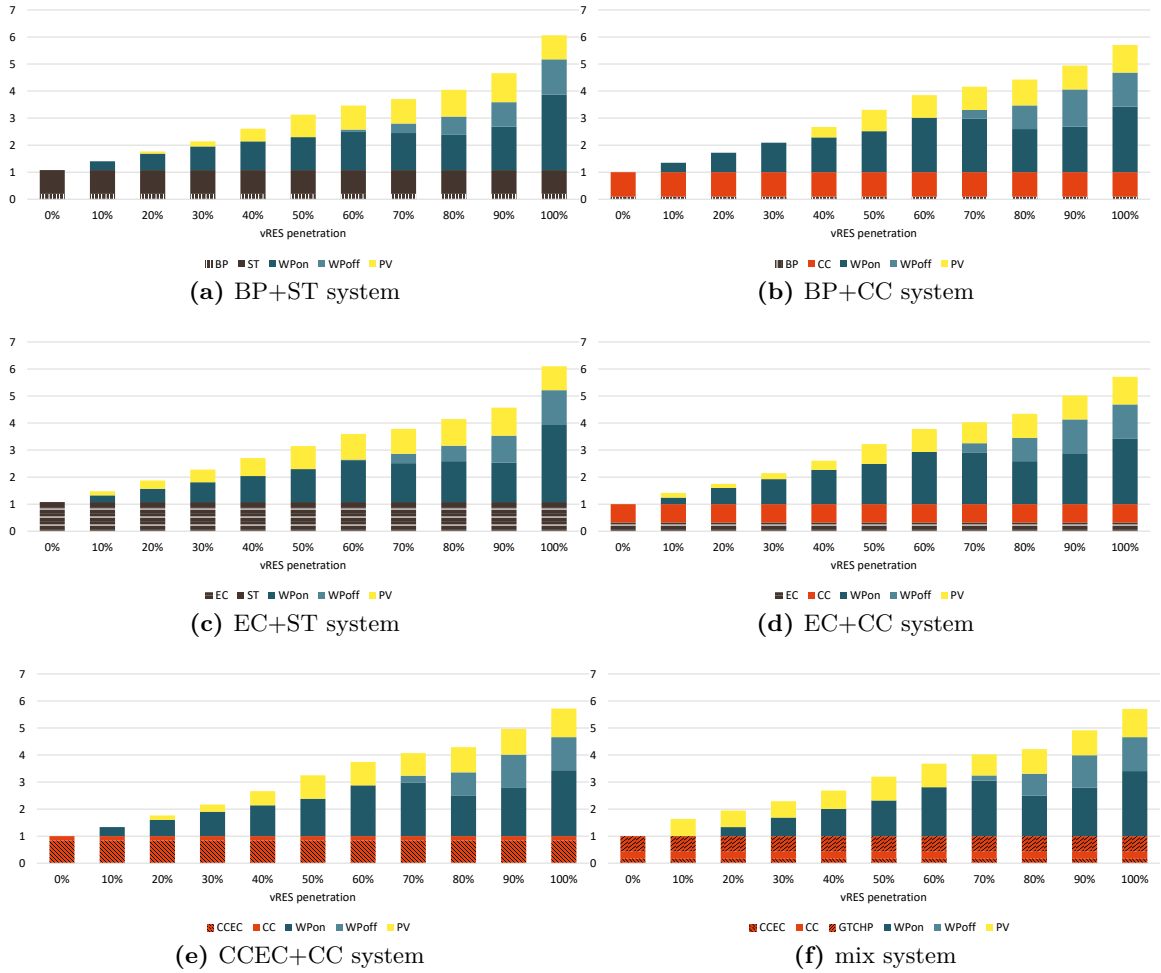
Source: 50Hertz et al. (2019).

Concerning vRES technologies, the time series for the capacity factors, $cf_{i,f,t}$, of PV, onshore, and offshore wind, is derived from historical data for installed capacity and actual generation in 2015 published by the transmission system operator (50Hertz, 2015).

3.5 Results

3.5.1 Power capacity and generation development

Figure 3.4 shows how investments in power generation capacity within the six systems develop as vRES penetration increases. Additionally, Figure 3.5 illustrates the capacities' actual contributions to power generation in each system. At 0% vRES penetration and without binding CO_2 emissions constraint, the model freely and endogenously determines the capacity mix from the set of available CHP and conventional power generation technologies. At higher vRES penetrations, this capacity mix stays fixed and the model endogenously determines additional capacities for vRES power generation, power-to-heat, and various storage. Turning now to the BP+ST system, the model determines only a



(a) BP+ST system

(b) BP+CC system

(c) EC+ST system

(d) EC+CC system

(e) CCEC+CC system

(f) mix system

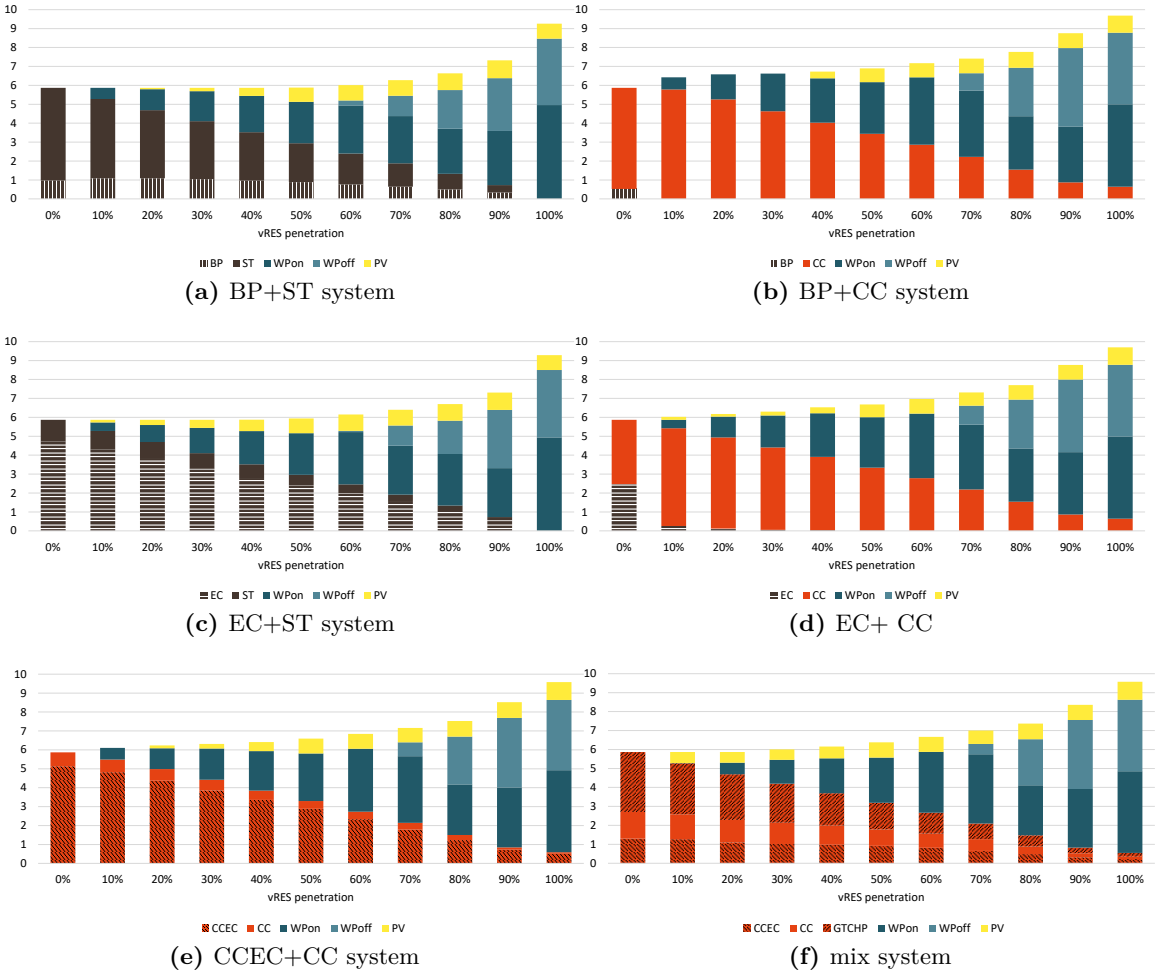
Figure 3.4: Development of power generation capacity over increasing vRES penetration in 100 MW_{el}.

small fraction of the required capacity to be of BP CHP technology, and the larger part to be conventional ST capacity. Thus, with perfect foresight, the operation of BP proves to be too inflexible with a higher capacity dimension to adapt to the usage cases in this system. Moreover, as Figure 3.5a shows, its contribution to the coverage of the residual load in the system is only minor. Most residual load is covered by the conventional ST plant in this system. In the EC+ST system, the model chooses the contrary and determines the larger part of power capacity to belong to an EC CHP plant. Thus, according to Figure 3.5c, it is the CHP plant that contributes most to the coverage of residual load. However, it is important to note that not all power generated in an EC CHP plant is necessarily cogenerated. Figure 3.5c does not reveal the share of CHP power generation within the system. What holds for the EC+ST system also holds for the CCEC+CC system, as illustrated by Figures 3.4e and 3.5e. Juxtaposing the BP and the EC CHP technologies with the uncoupled power and heat generation in the BP+CC and EC+CC systems, respectively, the model shows a clear preference for the uncoupled generation. The capacities of CHP are dimensioned smaller in each case compared to the systems with the conventional ST plants, demonstrated in Figures 3.4b and 3.4d, respectively. The actual power generation expressed in Figures 3.5b and 3.5d shows that in each system, the respective CHP plant becomes idle already at very low vRES penetrations.

Concerning the mix system, in which the model can freely choose from all coal and natural gas-fueled technologies at 0% vRES penetration, power demand is covered only with a technology mix fueled by natural gas. Figure 3.4f illustrates that more than half of this technology mix consists of GTCHP capacity, one quarter conventional CC capacity, and the rest CCEC capacity. The fact that natural gas fuel is significantly more costly than hard coal is compensated here through lower investment and fixed O&M costs as well as through higher efficiency and higher and less costly flexibility concerning load changes. In particular, GTCHP plants are very flexible and do not face any power losses when generating heat as well. However, among these technologies, GTCHP plants have the lowest electric efficiency and with increasing vRES penetration, its contribution to cover residual power load decreases the fastest, as shown by Figure 3.5f. At very high vRES penetrations such as 90% or 100%, where the CO_2 constraint is very tight, these gas-based technologies can still be operated fueled by synthetic gas generated by power-to-gas.

3.5.2 Heating capacity and heat generation development

Figures 3.6 and 3.7 show the development of heating capacity and its actual contribution to heat generation with increased vRES penetration in the six energy systems, respectively. When the model initially determines the technology mix at 0% vRES penetration, it invests in district heating boiler (DHB) capacity as much as necessary to cover the remaining difference between maximum heat load and the thermal capacity of the available CHP plant technology in the respective system. Hence, the lower the investments into CHP capacity, the more thermal capacity must be provided in the form of a DHB. With increasing vRES penetration in the system, the model additionally invests into power-to-heat, such as district heating electrode boilers (DHEBs) and ground source heat pumps (GSHPs). In



(a) BP+ST system (b) BP+CC system

(c) EC+ST system (d) EC+ CC

(e) CCEC+CC system (f) mix system

Figure 3.5: Development of power generation over increasing vRES penetration in 100 GWh_{el}.

comparison to the other systems, these investments appear in the BP+ST and EC+ST systems at rather higher vRES penetrations of 50% and 40%, respectively. In all other systems that are in combination with conventional CC plants, the use of power-to-heat already starts with vRES penetrations of 10% or 20%. In all systems with coal-fueled CHP technologies, contributions to heat generation by the respective CHP plant decrease faster than those by the DHB with increasing vRES penetration due to the higher CO_2 emissions intensity of coal. As Figures 3.7a and 3.7c show, at 90% and 100% vRES penetrations, DHB capacity can be still used under a tight CO_2 emissions constraint when using synthetic gas fuel generated by power-to-gas. If coal is eschewed, GSHPs become the dominating heating technology at a vRES penetration of 60% and higher as revealed by Figures 3.7e to 3.7f. DHEBs play only a minor role in the BP+ST and the EC+ST system.

3.5.3 Development of CHP efficiency and full load hours

Figure 3.8 depicts how each CHP technology performs in its isolated system in terms of average efficiency and full load hours with increased vRES penetration. For better illustration, full load hours are depicted here in usage percentage of capacity times 8,760 hours. In the BP+ST system, as shown by Figure 3.8a, the BP CHP plant constantly shows its maximum total fuel efficiency to be 90% with increased vRES penetration, since its technical configuration does not allow any operation points deviating from the back-pressure line, such that the power-over-heat-ratio stays constant. The decreasing full load hours indicate that ever fewer amounts of power and heat are generated at this high efficiency level with increasing vRES penetration. Full load hours first increase from 57% to 63% at 10% vRES penetration before continuously declining to 20%. This is explained by increasing system flexibility through investments into batteries and TES tanks, as shown in Figure B.1 in B.3. The storage capacities first allow for higher output levels of this inflexible technology before these outputs decrease due to the CO_2 emissions constraint. The BP+CC system does not permit such an analysis because the BP CHP plant becomes idle at very low levels of vRES penetration, as indicated by Figure 3.5b. The maximum fuel efficiency of the EC CHP plant in the EC+ST system is lower with 75%. However, actual efficiency is significantly lower on average, as depicted by Figure 3.8b: at 0% vRES penetration, the average fuel efficiency amounts to only 62% and increases to up to 67% at 70% vRES penetration, remaining constant thereafter. Nevertheless, this improvement in efficiency is more than offset by significantly decreasing full load hours of the EC CHP plant. Furthermore, the electric efficiency stays on average always five percentage points below its possible maximum value of 40%. The actual average power-over-heat-ratio proves to be much steeper than the σ-value of 0.8 of the plant's technical configuration. This is additionally illustrated by Figures 3.9a and 3.9b, which compare the respective frequency of operation points at 20% and 70% vRES penetration as an example. As depicted, at 20% vRES penetration, the operation point often deviates from the back-pressure line, which reduces the average total efficiency. At 70% vRES penetration, the operation points concentrate more on the back-pressure line, where the plant operates at maximum fuel efficiency, but also in areas of lower output level, leading to lower full load hours. The

EC+CC system does not permit such analysis because, again, the EC CHP plant mostly sits idle due to the fact that the model optimizes by means of uncoupled power and heat generation as depicted by Figure 3.5d.

In the CCEC+CC system, important shares of power and heat generation can be co-generated even at 60% vRES penetration, as seen in Figures 3.5e and 3.7e. Figure 3.8c also shows that the fuel efficiency rises from 67% at zero vRES penetration to up to 73% at 100% vRES penetration. Yet, capacity usage (full load hours) decreases from 69% to 7% with increasing contributions by vRES. Moreover, the CCEC plant's electric efficiency remains, on average, always five to six percentage points below the possible maximum electric efficiency of 52%. The average power-over-heat-ratio is much higher, and thus steeper, than the σ-value of 1.5 and is beyond the diagram's scale. Figures 3.9c and 3.9d illustrate the change in operation points for this type of CHP plant as well.

The mix system invests in CCEC and GTCHP capacity. The analysis is therefore split into Figures 3.8d and 3.8e, respectively. Concerning the CCEC plant, the depiction is similar to that of the CCEC plant in the CCEC+CC system; the GTCHP plant achieves significantly higher fuel efficiency of up to 85% compared to only 72% of the CCEC plant. However, full load hours are also substantially lower. The analysis in Figures 3.9e and 3.9f shows that this type of CHP plant with two degrees of freedom is most apt at operating at its maximum fuel efficiency at low or high vRES system penetrations for most of the time.

3.5.4 Analysis of extreme situations

Figure 3.10 illustrates for each energy system at 50% vRES penetration the power and heat generation in four different extreme situations: (i) low residual power and low heat load; (ii) high residual power and low heat load; (iii) low residual power and high heat load; and (iv) high residual power and high heat load. It is evident that power and heat generation in CHP mode is always strongest when residual power load is high and heat load is high as well, since this represents the most favorable case for CHP. An exception to this assertion is reflected in the BP+CC and the EC+CC systems; in these, even when heat load is high and the availability of vRES is low, leading to a high residual power load, power and heat are generated uncoupled by operating conventional CC plants, DHBs, and some power-to-heat in the form of GSHPs. The opposite case is when residual power load and heat load are low, a situation in which there are lots of vRES available and the low amounts of heat load can be covered by DHBs and power-to-heat. In situations of low residual power and high heat load, a pronounced use of power-to-heat can be expected. This is also supported by all systems apart from the BP+ST and the EC+ST system, where there are no or hardly any investments in power-to-heat capacity at 50% vRES penetration. In this situation, the BP+CC and EC+CC systems do not demonstrate any operation of CHP, which would be possible; instead, CC plants run simultaneously to power-to-heat facilities. In the case of high residual power and low heat load, a pronounced power generation by conventional power plants can be expected; however, at 50% vRES penetration, this cannot be shown in Figure 3.10, because power generation by vRES already dominates in the identified extreme hours in the six various systems analyzed.

3.6 Conclusion

The individual analyses of various CHP technologies in combination with uncoupled power and heat generation technologies as an alternative in six different stylized energy systems allowed for an examination of the interaction with other technologies and performance of each CHP technology in terms of fuel efficiency and full load hours in the context of increasing system penetration by variable renewable energy sources. The examined CHP technologies were back-pressure steam turbines, extraction-condensation steam turbines, combined-cycle extraction-condensation CHPs, and gas turbine CHPs.

The analysis showed that back-pressure steam turbines can be dimensioned only to cover a small share of maximum power and heat load. Due to its strictly coupled power-over-heat-ratio, this CHP type is too inflexible and operates on the basis that it is driven by heat loads. Therefore, this CHP capacity is only practical when covering small shares of power and heat demand and must be accompanied respectively by large capacities for uncoupled power and heat generation. Increasing penetration by variable renewable energy sources has no influence on its high fuel efficiency. Yet, the high efficiency may be exploited to a lesser degree with a decrease in full load hours.

In contrast, an extraction-condensation steam turbine can be dimensioned significantly larger in the same energy system, as it can also partly or fully operate conventionally. Thus, it covers most of the residual power load, given that a conventional steam turbine is the alternative. When penetration by variable renewable energy sources increases, an extraction-condensation steam turbine runs on the back-pressure line even more often. This increases its average fuel efficiency, which is mostly 13 to eight percentage points below the maximum and decreases its electrical efficiency, which is about five percentage points below the maximum. However, operation points also concentrate more on lower output levels of the back-pressure line, which corresponds to a decrease in full load hours.

In both cases, when comparing the back-pressure steam turbine and the extraction-condensation steam turbine to uncoupled power and heat generation via a combined-cycle gas turbine and a heat boiler, the uncoupled power generation proves to be advantageous. At low penetration by variable renewable energy sources, both CHP types become idle, since the uncoupled power and heat generation technologies provide a higher electrical and thermal efficiency, respectively. Even in situations of high heat loads, the model does not operate the available CHP plants.

Only a combined-cycle extraction-condensation CHP can compete with the uncoupled alternative of a combined-cycle gas turbine and a heat boiler. Here, too, fuel efficiency increases with increasing penetration by variable renewable energy sources, which is offset by a decrease in full load hours. The plant operates on the back-pressure line more often, yet with lower power and heat output levels. Compared to the combined-cycle gas turbine, the electrical efficiency of the combined-cycle extraction-condensation CHP is always five to six percentage points lower.

Leaving the choice of technology open to the model reveals that most investments go into capacity of gas turbine CHP with some into capacities for combined-cycle gas turbines and combined-cycle extraction-condensation CHPs. This type of CHP proves to be most

apt at running closely to its maximum fuel efficiency and electrical efficiency at low or high penetration by variable renewable energy sources. Nevertheless, with increasing variable renewable energy sources, its contributions to the coverage of residual power demand and, thus, full load hours, decrease substantially faster compared to the combined-cycle gas turbine and combined-cycle extraction-condensation CHP.

In general, with increasing penetration by variable renewable energy sources, fuel efficiency of all CHP technologies with two degrees of freedom actually increases. However, this higher fuel efficiency is offset by decreasing full load hours. Even though the CHP technology is fueled by synthetic gas from power-to-gas at very high penetration by variable renewable energy sources, CHP technology no longer plays a role. The share of CHP power generation in the residual power generation actually increases, whereas its share in the heat generation decreases, as it is substituted by power-to-heat technologies like ground source heat pumps and electric boilers.

Acknowledgment

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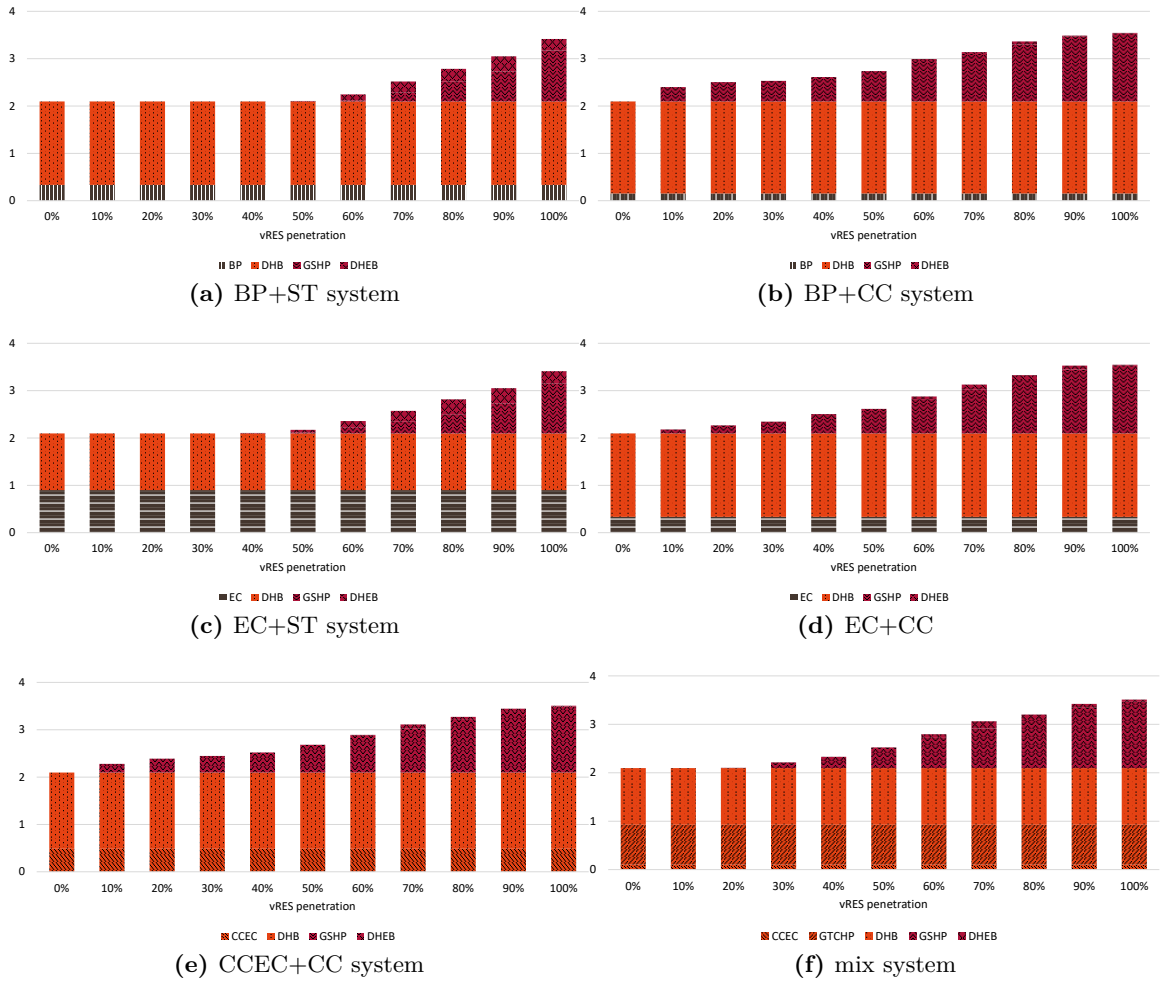


(a) BP+ST system

(b) BP+CC system

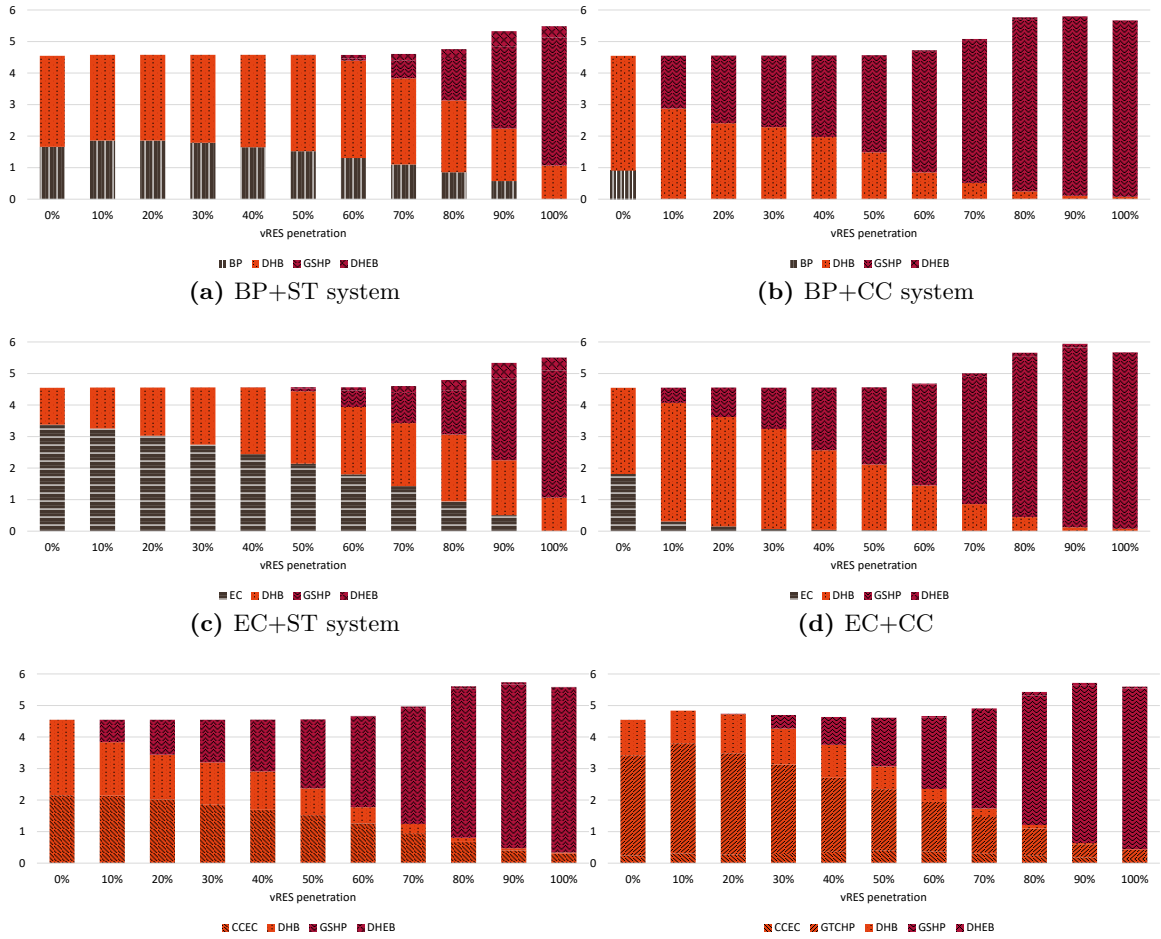
(c) EC+ST system

(d) EC+CC

(e) CCEC+CC system

(f) mix system

Figure 3.6: Development of heat generation capacity over increasing vRES penetration in in 100 MW_{th}.



(a) BP+ST system

(b) BP+CC system

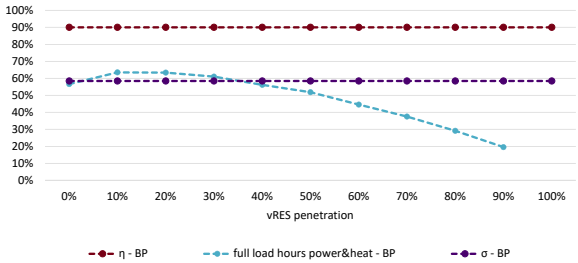
(c) EC+ST system

(d) EC+CC

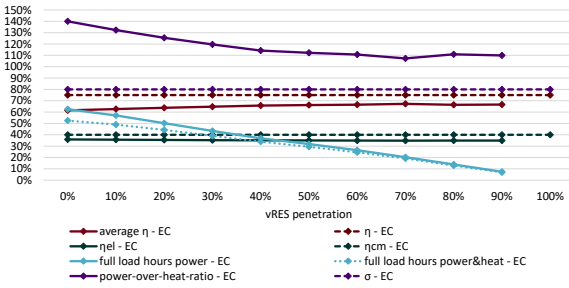
(e) CCEC+CC system

(f) mix system

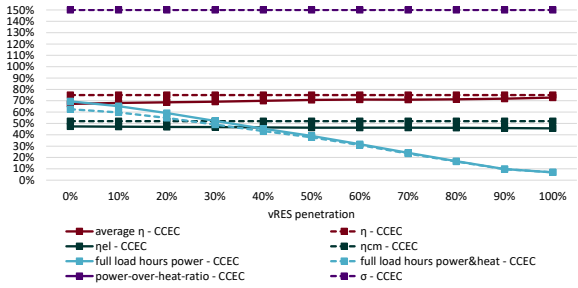
Figure 3.7: Development of heat generation over increasing vRES penetration in 100 $\mathrm{GWh_{th}}$.



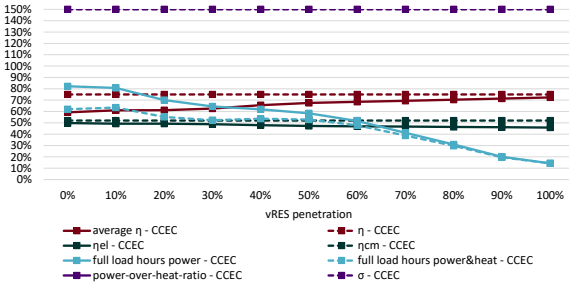
(a) BP+ST system



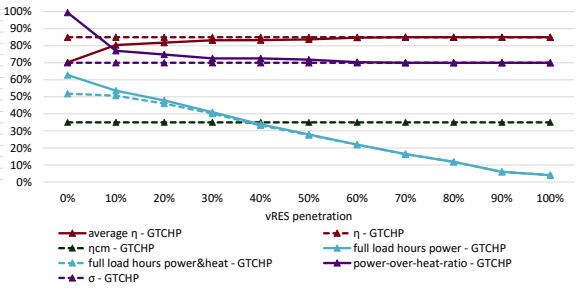
(b) EC+ST system



(c) CCEC+CC system

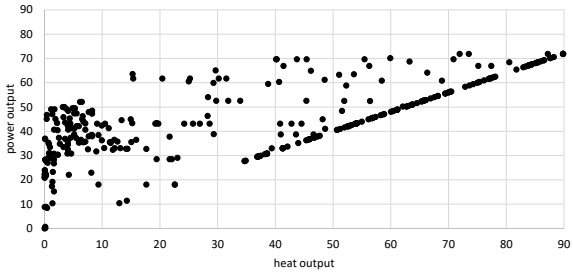


(d) mix system CCEC

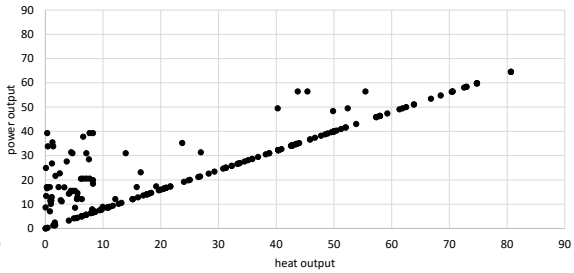


(e) mix system GTCHP

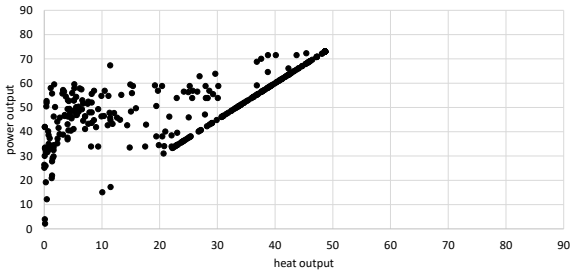
Figure 3.8: Development of CHP efficiency and full load hours over increasing vRES penetration.



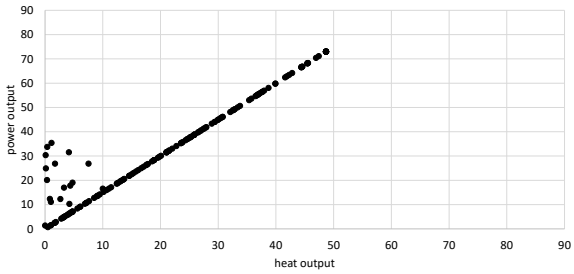
(a) EC plant in EC+ST system at 20% vRES



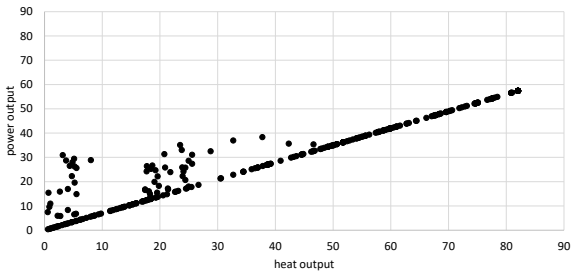
(b) EC plant in EC+ST system at 70% vRES



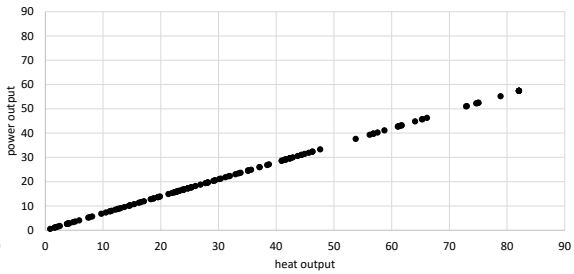
(c) CCEC plant in CCEC+CC system at 20% vRES



(d) CCEC plant in CCEC+CC system at 70% vRES

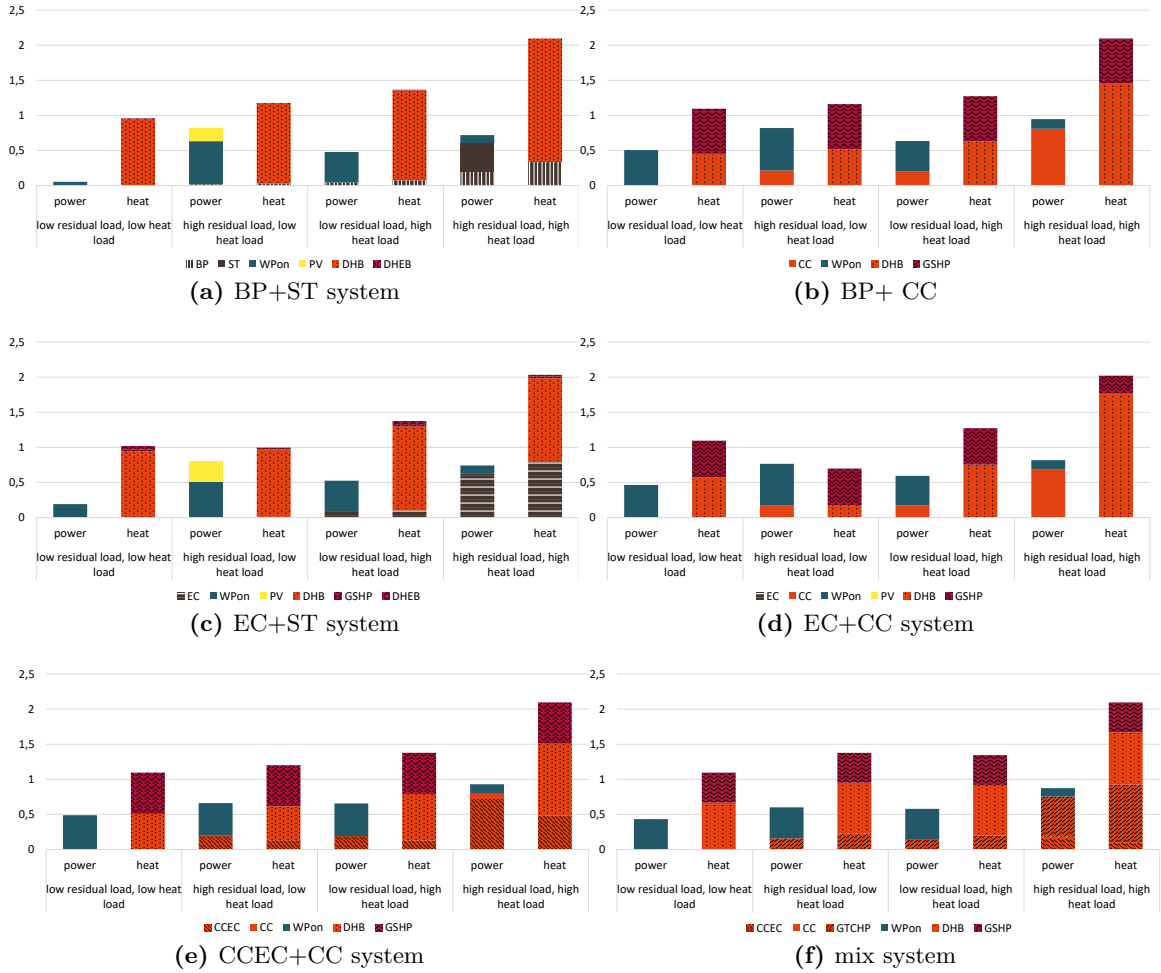


(e) GTCHP plant in mix system at 20% vRES



(f) GTCHP plant in mix system at 70% vRES

Figure 3.9: Change in operation points of EC, CCEC, and GTCHP plants at 20% and 70% vRES penetration in MW_{el} and MW_{th}, respectively.



(a) BP+ST system (b) BP+ CC

(c) EC+ST system (d) EC+CC system

(e) CCEC+CC system (f) mix system

Figure 3.10: Power and heat generation composition in extreme situations at 50% vRES penetration in 100 MW_{el}.

4 Impacts of heat sector transformation on Germany's power system through increased use of power-to-heat

Impacts of heat sector transformation on Germany's power system through increased use of power-to-heat

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Highlights

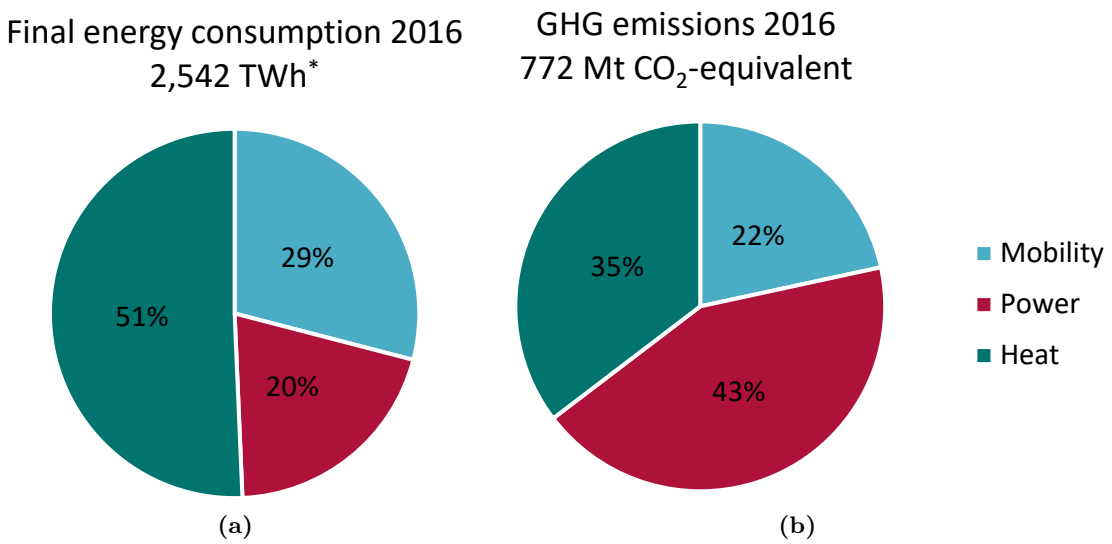
- Extension of European power sector model to also include the German heat demand sector.
- Detailed modeling of combined heat and power (CHP) and power-to-heat technologies.
- Findings: Up to additional 260 $\mathrm{TWh_{el}}$ of electricity demand through power-to-heat.
- Additional power is covered by capacity expansions of wind, gas and imports.
- Power storage capacity development shifts over from battery to power-to-gas technology.

Abstract

The heating sector accounts for a major part of Germany's energy consumption and carbon emissions. Both, renewable energy and power-to-heat, could help decarbonizing it. To analyze the impacts of power-to-heat and heat storage on power system development, a dynamic long-term power sector investment and dispatch model for Europe is extended to also include German individual and district heating. Findings show that power-to-heat causes a substantial rise in electricity demand, even if heat energy demand decreases strongly. Power generation from wind and natural gas accordingly increase. Power-to-gas capacity increasingly substitutes battery storage. Combined heat and power does not play a role in future scenarios.
Keywords: power sector modeling, sector coupling, power-to-heat
JEL codes: C61, D61, Q42
Journal: Applied Energy 239 (2019), https://doi.org/10.1016/j.apenergy.2019.01.101

4.1 Introduction

In 2010, the German Federal Government announced a climate and energy policy with concretely defined quantitative targets in terms of reductions in greenhouse gas (GHG) emissions and energy consumption, as well as growth in production from renewable energy sources (RESs) (BMWi and BMU, 2010). Subject to frequent changes and adjustments, the policy is now known internationally as the *energiewende* – the "energy transition" (Hake et al., 2015; Hirschhausen, 2014). Under this policy, the power sector has made especially important achievements in fulfilling the targets and in decarbonizing the energy sector. However, the heat and mobility sectors are not experiencing such a significant transformation. Since 1990, RES increased its share of gross power generation from 3.4% to 29% in 2016, while the heat sector saw its share rise from 2.1% to 13% and in the mobility sector from nearly zero to 5.2% (BMWi, 2017). Nevertheless, heating and mobility are equally important in pursuing the *energiewende* objectives, especially considering their share in consumption and greenhouse gas emissions, as depicted in Figure 4.1.



* In a simplifying way, all energy carriers, other than power or for mobility services, are counted as contributing to final energy consumption of heating.

Figure 4.1: Sectoral contribution to final energy consumption and greenhouse gas (GHG) emissions in Germany in 2016.

Source: Own depiction based on AGEB (2017) and BMWi (2017).

Due to the limited availability of biomass as an RES for the heat and mobility sectors, electricity generated from RES will play a crucial role in making these sectors switch to alternative energy sources. This necessarily leads to an increase in the demand for electricity, which some studies estimate will rise from 545 TWh_{el} in 2014 to 788 TWh_{el} in 2050,

even accounting for energy consumption reductions (Agora, 2015). The implication of such a development is that not only would the objective of reducing gross power consumption to 480 TWh_{el} in 2050 be missed, it would lead to ever higher capacity requirements of wind and photovoltaics (PV) power in order to cover at least 80% of this remaining power consumption with RES in 2050, as formulated by the governmental targets. On the other hand, new power consumers in the heat and mobility sectors, such as power-to-heat units or electric vehicles, can provide flexibility to the power sector's demand side and, hence, assist in integrating RES for electricity (RES-E) into the energy system as a whole (Bloess, Schill, and Zerrahn, 2018; Kiviluoma and Meibom, 2010). Commonly discussed integration measures include transmission expansion, electric storage, demand side management (DSM) within the power sector, and flexibilization of conventional generators (Kondziella and Bruckner, 2016). Such issues are usually discussed in power-only sector models. A power-only sector model, such as by F. U. Leuthold, Weigt, and Hirschhausen (2012), is understood here as a partial equilibrium model not considering any energy form other than electricity. It only aims to cover conventional power demand, excluding substantial additional power demands due to power-to-heat and power-to-gas applications or electric vehicles. Moreover, it neglects technical characteristics and constraints for power generating plants that simultaneously supply heat, such as combined heat and power (CHP) plants. Further, power-only system modeling neglects further flexibilization options from sector coupling. Storing energy in the form of heat, which certainly can be made use of for heating purposes at a later point in time, is achievable with state-of-the-art technology and at significantly lower costs compared to storing electricity (Østergaard, 2012). Therefore, an enhanced power and heat sector coupling can benefit the heat sector's transformation as well as decrease the costs of RES integration in the power sector.

The aim of this paper is twofold: first, it enlarges the view of an already existing power-only sector model named dynELMOD by Gerbaulet and Lorenz (2017) by means of extending it to both individual and district heating supplies for Germany. This enables capturing the methodological differences between neglecting and incorporating this additional energy sector. Second, when the German heat sector transforms with either an ambitiously reduced or possibly constant energy demand in the future, it provides lower and upper estimates of additional electricity demand through power-to-heat technology. For these cases, it shows the required RES and storage capacity expansions, which must be taken into account politically.

In terms of methodology, this paper proposes a techno-economic modeling framework that combines several features. Extending the European long-term electricity sector cost optimization model dynELMOD to incorporate the German heat sector, dynELMOD+heat facilitates the analysis of expansion paths of variable RES and conventional power generation along with its effects from interacting with CHP and heat-only plants, conventional technologies for individual heating, heat storage and various kinds of power-to-heat technologies. Despite the model's long-term character under a tightening yearly European CO_2 emissions constraint, power and heat demand must be covered hourly in the short term. The model allows for endogenous investments into generation, storage, and transmission capacities in the European power system and into heat generation technologies in the Ger-

man heat sector. Dispatch and investments are solved simultaneously for power and heat demand. On the one hand, this extension is used here to show quantitative differences between incorporating and neglecting the heating sector, which is important to better understand the methodological approach of limiting the view on a power-only system. On the other hand, the extension is used to analyze the quantitative impacts of additional power demand through increasing power-to-heat, on RES capacity and generation, as well as on storage capacity developments in the German power sector through 2050. Since additional electric energy demand for heating purposes and the heating demand itself are not taken into account in a power-only system model, the extension here allows a more comprehensive view of the sectors' interaction. The major contributions of this paper is an analysis that combines several features as follows:

(1) a joint power and heat sector dispatch and investment model with a high degree of detail for energy technologies in Germany;

(2) a dynamic long-term view starting from the present energy system with development through 2050 under assumptions for technical progress and tightening emission constraints; and

(3) the combination of different flexibility options for variable RES integration, such as storage, demand side management and heat sector coupling embedded in the European electricity market for cross-border power exchanges.

The insights gained from this analysis provide power sector modelers with a better overview concerning the quantities in capacity and generation expansions in RES, storage, and other conventional generation as well as how they are driven in such a model through power-to-heat, when considering power and heat sector coupling. Further, the role of power-to-heat in conjunction with heat storage, among the other aforementioned flexibility options for the integration of variable RES, can be illustrated thanks to considering the heating supply and interactions with it. Furthermore, the insights illustrate to policy makers the expectable quantities of additional power demand in future developments under rigid CO_2 emissions constraints according to currently pursued policies concerning heat energy demand and when those policies are not met in reality.

To the best knowledge of the author, no other modeling exercise for Germany combines the power sector with the individual and district heating sectors at such high degree of detail concerning the various technologies that is simultaneously embedded into the European power market in a long-term view. The following literature overview highlights other approaches in this field and contrasts them to the approach proposed in this paper.

4.1.1 Modelling of power and heat sector coupling

In order to capture the effects of sector coupling, there is a fast growing literature employing a variety of approaches, which is reviewed in Wu et al. (2016). Brown et al. (2018) point out that there are two competing concepts in the literature for integrating high shares of variable RES. One concept is reinforcing over-regional transmission capacity, whereas the

other aims for flexibility through the coupling of different energy sectors. However, a combination of the two, as in Ashfaq et al. (2017) and Brown et al. (2018) or as in this work, is rarely found. An overview focusing on the coupling of the power and heat sectors is provided by Bloess, Schill, and Zerrahn (2018). A few of these approaches are noteworthy here. Some authors only emphasize the linkage of the power system with the centralized heat supply through district heating networks (Abdollahi, Wang, and Lahdelma, 2016; Blarke, 2012; Kiviluoma and Meibom, 2010; J. Li et al., 2016; Nielsen et al., 2016). Blarke (2012) and Nielsen et al. (2016) look at a single district heating network equipped with a heat pump and/or an electric boiler. On the other hand, Blarke (2012) takes a holistic energy system view to compare different technology configurations in terms of their intermittency-friendliness in a power system with a high share of variable RES, while Nielsen et al. (2016) take the view of an individual CHP plant acting in a liberalized energy market and analyze the benefits of power-to-heat technology to deal with price uncertainty for power and heat products in the context of the day-ahead market. The work by Abdollahi, Wang, and Lahdelma (2016) is specialized on the optimal dispatch of several CHP plants in different supply areas with a methodological focus on a faster computation technique. The paper by J. Li et al. (2016) also has a methodological focus on computation efforts, however their work aims for a detailed network topology and the optimal coordination of energy flows in power transmission and district heating distribution networks. All these works seek to optimize the dispatch of existing capacities and do not aim for optimized investment decisions. In contrast, Kiviluoma and Meibom (2010) aim for optimal investment decisions, taking a broader view to examine additional flexibility of the power system through coupling with the heat sector and the deployment of electric vehicles to better integrate fluctuating wind power. Therefore, they apply the quantitative techno-economic cost-optimization model BALMOREL on Finland in a simulation for the single year 2035. However, this work does not consider individual heat supply.

Another strand of the literature looks exclusively at interactions of the power system with decentralized individual heat supply (Merkel, Fehrenbach, et al., 2014; Oluleye et al., 2018; Patteeuw, Bruninx, Arteconi, et al., 2015). Merkel, Fehrenbach, et al. (2014) stress that pooling different individual heating technologies to cover an aggregated demand as commonly conducted for power systems would lead to a distorted heat generation mix, because the individual heating sector is fractionated without a transport system and households cannot switch between different heat generation technologies in the short term. The authors address this issue in the TIMES modeling environment and modify it, aiming to represent more realistic heat technology mix developments over the future at the cost of introducing integer variables. However, in this work, the issue is accounted for by keeping a linear program as outlined in Section 4.2 on methodology. Patteeuw, Bruninx, Arteconi, et al. (2015) conduct an integrated modeling of the power system including electric heating systems subject to an active demand response scheme, which takes into account the dynamics and constraints of the power system's supply and demand side. Active demand response is defined here as a behavior by end-consumers to deviate from their conventional electricity usage based on price signals. Comparing their model approach to others, they find that their merit order model is a good candidate for full year calculations, but the

integration leads to significantly higher computational efforts. The work by Oluleye et al. (2018) use a case study consisting of several hundred prosumers in a typical UK urban area and apply a two-step optimization approach to quantify the flexibility potential provided by individual power-to-heat and thermal energy storage in dwellings.

Other works either do not strictly distinguish between the individual and district heating sectors or, as this work, take both into account, typically putting a stronger emphasis on one of them (Bauermann, Spiecker, and Weber, 2014; Fehrenbach et al., 2014; Hedegaard and Balyk, 2013; X. Zhang et al., 2018). E.g. Hedegaard and Balyk (2013) extend BALMOREL, which already accounts for district heating, with the thermal building model add-on that comprises the one-family house heating demand of Denmark with individual heat pumps, thermal storage tanks, as well as passive and active heat storage in the building mass. In Bauermann, Spiecker, and Weber (2014), an integrated and iterative modeling approach is presented to determine the development of the German heating market. The authors combine the linear stochastic power market optimization model E2M2 with the individual discrete choice model for heating systems HeatSyM. Fehrenbach et al. (2014) employ TIMES-HEAT-POWER, which is a highly technology-explicit model in the power and residential heat sector to analyze thermal capacity and dispatch developments in Germany in 2010, 2030, and 2050 with several scenarios of various exogenous developments of electrical RES capacities. Although district heating among other technologies is assumed to cover the residential sector's heat demand, centralized large CHP plants are neglected in the study and they focus on the evolution of heat pumps, thermal storage and individual micro-CHP. Among other results, their comparison of thermal versus electric storage suggests significantly more capacity evolution in the former. The work by X. Zhang et al. (2018) assesses, first, the full deployment and, secondly, the optimized mix of heat pumps, hybrid heating by combining heat pumps and gas boilers , and district heating in a whole-system analysis of the UK under two differently strict emission constraints. A unique feature of this modeling exercise is its incorporation of power transmission and distribution reinforcement costs associated with large-scale power-to-heat deployment as well as district heating network expansion costs.

Several works aiming for an integrated power and heat sector analysis apply methods other than cost optimization (Barton, Huang, et al., 2013; Østergaard and Henrik Lund, 2011; Pensini, Rasmussen, and Kempton, 2014; Waite and Modi, 2014). Among those applying cost optimizations, many are static models merely looking at a single year (Arteconi et al., 2016; Blarke, 2012; Brown et al., 2018; Hedegaard and Balyk, 2013; Kirkerud et al., 2014; Kiviluoma and Meibom, 2010; Østergaard and Henrik Lund, 2011; Patteeuw, Bruninx, Arteconi, et al., 2015; X. Zhang et al., 2018). Only a few, and likewise the approach presented in this work, aim to identify development over the long term by use of dynamic models (Bauermann, Spiecker, and Weber, 2014; Dodds, 2014; Fehrenbach et al., 2014; Merkel, Fehrenbach, et al., 2014). Furthermore, only a minority of optimization models allow for endogenous investment decisions (Bauermann, Spiecker, and Weber, 2014; Dodds, 2014; Hedegaard and Balyk, 2013; Kiviluoma and Meibom, 2010; Merkel, Fehrenbach, et al., 2014).

The rest of the paper is organized as follows: Section 4.2 gives a detailed formulation

of the model extension. The scenarios applied in order to illustrate the aforementioned aspects are presented in Section 4.3 along with the data sources and required assumptions. Section 4.4 illustrates the computations' outcomes, which is followed by a short discussion of the model's mechanics and limits in Section 4.5. The last Section 4.6 draws conclusions.

4.2 Method

DynELMOD is a dynamic partial equilibrium power-only sector model covering 33 European countries. It uses linear cost optimization to determine endogenously investments into conventional and RES generation and storage capacity, as well as into transmission capacity between countries over a long-term horizon through 2050 (Gerbaulet and Lorenz, 2017). In the short term, it economically optimizes the hourly dispatch of all these capacities. Originally, it is based on ELMOD, which is a static power sector investment and dispatch model (F. U. Leuthold, Weigt, and Hirschhausen, 2012). Figure 4.2 illustrates its extension to dynELMOD+heat, which includes low temperature individual and district heating demand. On the supply side, the extension covers all heating technologies relevant in Germany. As dynELMOD is documented in detail elsewhere (Gerbaulet and Lorenz, 2017), this section focuses only on features relevant for the heat sector extension. A nomenclature for symbols is found in appendix C.1. To improve readability, variables consist of capital letters, while parameters are in lower case letters. For simplicity, the model formulation presents only possibly newly built capacities. The formulation for pre-existing capacities is analogous, with the only difference being that newly installed capacities, $\overline{G}_{i,yy}$, $\overline{Q^{DH}_{i,yy,hz}}$ and $\overline{Q^{IH}_{i,yy}}$, are variables with a vintage index yy and existing capacities, $\overline{g}_{p,i,y}$, $\overline{q^{DH}_{p,i,y,hz}}$ and $\overline{q^{IH}_{i,y}}$, are parameters without vintage index. Whereas new capacities are represented as aggregates, all existing conventional and CHP power generators are implemented block sharp and indexed by p. Since the heat sector extension accounts only for Germany, the country index is omitted here for all variables and parameters for clarity.

4.2.1 Objective function

The objective function for total system costs of dynELMOD (4.1) is extended with sum terms for operation, OC^H, fixed operation and maintenance, $O\&MC^H$, as well as investment costs, IC^H, for CHP plants (CHP), cogeneration units (CUs)[1], and heat-only generation facilities (OH). Equations (4.2)-(4.5) define these costs in more detail.

$$TC = ... + OC^H + O\&MC^H + IC^H \tag{4.1}$$

The operation costs (4.2) consist of fuel consumption, $F_{i,t,y,yy}$, of each technology i, at time slice t in year y with vintage yy and of ramping cost for load changes up, $G^{up}_{i,t,y}$, and down, $G^{dn}_{i,t,y}$. Note that for only heat generating facilities, there are only generation costs, if they

[1] In this work, CHP plant relates only to large-scale plants connected to district heating. In contrast, cogeneration unit (CU) refers to decentralized small-scale power and heat generating units for individual heating.

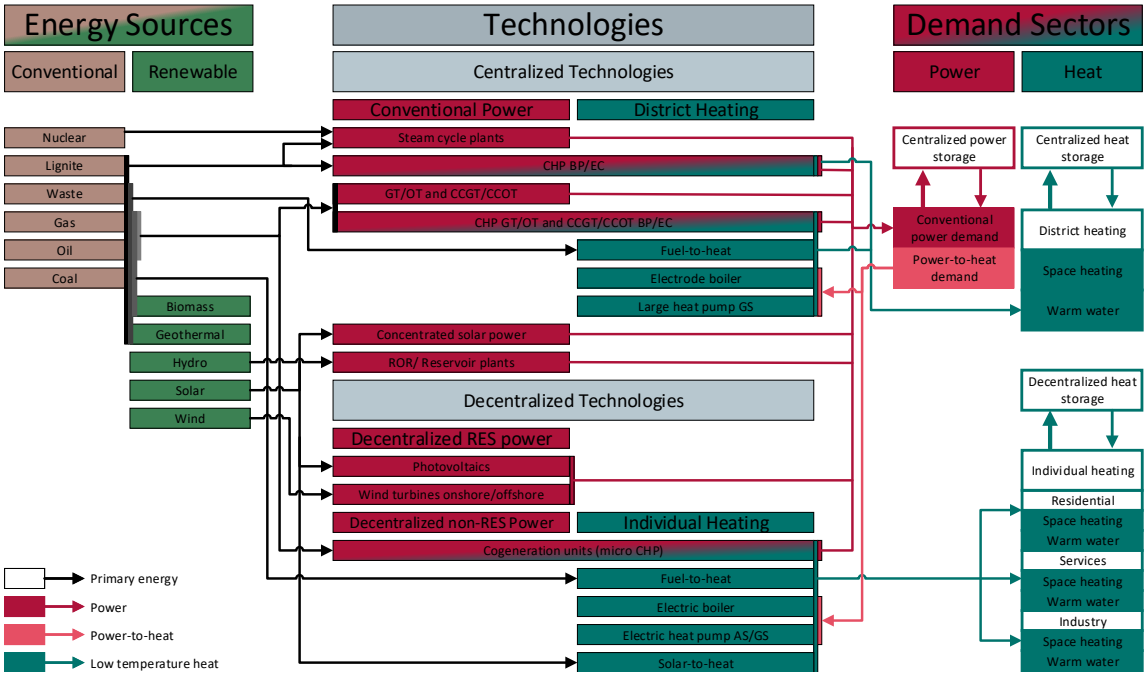


Figure 4.2: DynELMOD+heat model scheme.

Source: Own depiction.

are burning fuel like fuel-to-heat (F2H) facilities. Other only heat generating facilities are either based on RES with zero costs or on power. The operation costs for power-to-heat are endogenously determined in the model's power sector part.

$$OC^H = \sum_t \sum_y df_y \left(\sum_{y-tlt<yy\leq y} \left(\sum_{i\in CHP} \left(c^{var}_{i,y,yy} \cdot F_{i,t,y,yy} \right) + \sum_{i\in F2H^{DH}} \left(c^{var}_{i,y,yy} \cdot F_{i,t,y,yy} \right) \right.\right.$$
$$\left. + \sum_{i\in CGU} \left(c^{var}_{i,y,yy} \cdot F_{i,t,y,yy} \right) + \sum_{i\in F2H^{IH}} \left(c^{var}_{i,y,yy} \cdot F_{i,t,y,yy} \right) \right)$$
$$\left. + \sum_{i\in CHP} \left(c^{ram}_{i,y} \cdot \left(G^{up}_{i,t,y} + G^{dn}_{i,t,y} \right) \right) \right) \tag{4.2}$$

Due to different relationships between fuel input, $F_{i,t,y,yy}$, and output of power, $G_{i,t,y,yy}$, of district heat, $Q^{DH}_{i,t,y,yy,hz}$, or of individual heat, $Q^{IH}_{i,t,y,yy}$, in several technologies, they must be distinguished as illustrated in equations (4.3). The technical properties differ for back-pressure CHP plants (4.3a), for CHP plants with power loss, such as extraction-condensation CHP plants or open-cycle gas turbines with heat recovery boiler (4.3b), for fuel-to-heat plants in district heating (4.3c), as well as for cogeneration units (4.3d) and

for fuel-to-heat capacities in individual heating (4.3e).

$$F_{i,t,y,yy} = \frac{1}{\eta_{i,yy}} \cdot \left(G_{i,t,y,yy} + \sum_{hz} Q^{DH}_{i,t,y,yy,hz} \right) \qquad \forall\ i \in CHP^{BP}, t, y, y - tlt < yy \leq y \tag{4.3a}$$

$$F_{i,t,y,yy} = \frac{1}{\eta^{CM}_{i,yy}} \cdot \left(G_{i,t,y,yy} + \beta_{i,yy} \cdot \sum_{hz} Q^{DH}_{i,t,y,yy,hz} \right) \quad \forall\ i \in CHP^{PL}, t, y, y - tlt < yy \leq y \tag{4.3b}$$

$$F_{i,t,y,yy} = \frac{1}{\eta_{i,yy}} \cdot \sum_{hz} Q^{DH}_{i,t,y,yy,hz} \qquad \forall\ i \in F2H^{DH}, t, y, y - tlt < yy \leq y \tag{4.3c}$$

$$F_{i,t,y,yy} = \frac{1}{\eta_{i,yy}} \cdot \left(G_{i,t,y,yy} + Q^{IH}_{i,t,y,yy} \right) \qquad \forall\ i \in CGU, t, y, y - tlt < yy \leq y \tag{4.3d}$$

$$F_{i,t,y,yy} = \frac{1}{\eta_{i,yy}} \cdot Q^{IH}_{i,t,y,yy} \qquad \forall\ i \in F2H^{IH}, t, y, y - tlt < yy \leq y \tag{4.3e}$$

All existing and newly built capacities have fixed operation and maintenance costs according to (4.4).

$$\begin{aligned} O\&MC^{H} = \sum_{y} df_y \sum_{y-tlt<yy\leq y} \Bigg(& \sum_{i\in CHP} \left(c^{fix}_{i,y} \cdot \overline{G}_{i,yy} \right) + \sum_{i\in OH^{DH}} \left(c^{fix}_{i,y} \cdot \sum_{hz} \overline{Q^{DH}_{i,yy,hz}} \right) \\ & + \sum_{i\in CGU} \left(c^{fix}_{i,y} \cdot \overline{G}_{i,yy} \right) + \sum_{i\in OH^{IH}} \left(c^{fix}_{i,y} \cdot \overline{Q^{IH}_{i,yy}} \right) \Bigg) \end{aligned} \tag{4.4}$$

Equation (4.5) illustrates investment costs for newly built capacities. All present and future costs are discounted to the present by the discount factor df_y.

$$\begin{aligned} IC^{H} = \sum_{y} df_y \sum_{y-tlt<yy\leq y} \Bigg(& \sum_{i\in CHP} \left(c^{inv}_{i,yy} \cdot \overline{G}_{i,yy} \right) + \sum_{i\in OH^{DH}} \left(c^{inv}_{i,yy} \cdot \sum_{hz} \overline{Q^{DH}_{i,yy,hz}} \right) \\ & + \sum_{i\in CGU} \left(c^{inv}_{i,yy} \cdot \overline{G}_{i,yy} \right) + \sum_{i\in OH^{IH}} \left(c^{inv}_{i,yy} \cdot \overline{Q^{IH}_{i,yy}} \right) \\ & + \sum_{i\in HS} \left(c^{inv}_{i,yy} \cdot \overline{HS}_{i,yy} \right) \Bigg) \end{aligned} \tag{4.5}$$

4.2.2 Energy balance for power

The power balance (4.6) of dynELMOD experiences a modification on its supply side through additional generation from CHP plants and cogeneration units. On its demand side, this occurs through an additional variable summing up all power demand through power-to-heat generation, $Q^{P2H}_{t,y}$. Equation (4.7) specifies the latter in more detail. Note that, for heat pumps, the actual coefficient of performance (COP) $\epsilon_{i,t,y,yy}$ depends on the Carnot-COP and the quality grade $\omega_{i,yy}$. The latter indicates how well the Carnot-COP can be technically reached. Where the Carnot-COP depends on the temperature of the heat source, $\vartheta^a_{t,y}$, and sink, ϑ^s_{yy}, the quality grade is subject to technical progress over time. Moreover, technical progress can also result in lower required supply temperatures, T^s_{yy}. Hence, the actual coefficient of performance is determined according to $\epsilon_{i,t,y,yy}(\omega_{i,yy}, \vartheta^a_{t,y}, \vartheta^s_{yy}) = \omega_{i,yy} \cdot \epsilon^{Carnot}_{t,y,yy}(\vartheta^a_{t,y}, \vartheta^s_{yy}) = \omega_{i,yy} \cdot \frac{T^s_{yy}}{T^s_{yy} - T^a_{t,y}}$. For ground source heat pumps (GSHPs), the heat source is assumed to have a constant temperature level, which simplifies its COP, $\epsilon^{GS}_{i,yy}$, in comparison to an air source heat pump (ASHP), $\epsilon^{AS}_{i,t,y,yy}$.

$$q_{t,y} + Q^{P2H}_{t,y} = ... + \sum_{y-tlt<yy\leq y} \left(\sum_{i\in CHP} G_{i,t,y,yy} + \sum_{i\in CGU} G_{i,t,y,yy} \right) \qquad \forall\ t, y \tag{4.6}$$

$$\begin{aligned} Q^{P2H}_{t,y} = \sum_{y-tlt<yy\leq y} \Bigg(& \sum_{i\widehat{=}EB^{DH}} \left(\frac{1}{\eta_{i,yy}} \cdot \sum_{hz} Q^{DH}_{i,t,y,yy,hz} \right) + \sum_{i\widehat{=}GSHP^{DH}} \left(\frac{1}{\epsilon^{GS}_{i,yy}} \cdot \sum_{hz} Q^{DH}_{i,t,y,yy,hz} \right) \\ & + \sum_{i\widehat{=}EB^{IH}} \left(\frac{1}{\eta_{i,yy}} \cdot Q^{IH}_{i,t,y,yy} \right) \\ & + \sum_{i\widehat{=}ASHP^{IH}} \left(\frac{1}{\epsilon^{AS}_{i,t,y,yy}} \cdot Q^{IH}_{i,t,y,yy} \right) + \sum_{i\widehat{=}GSHP^{IH}} \left(\frac{1}{\epsilon^{GS}_{i,yy}} \cdot Q^{IH}_{i,t,y,yy} \right) \Bigg) \quad \forall\ t, y \end{aligned} \tag{4.7}$$

4.2.3 Energy balance for district and individual heating

The energy balance (4.8) of district heating supply zones, $hz \in HZ$, comprises technologies not available in individual heating systems, such as CHP plants and large centralized heat storage. Additionally, the balance accounts for transmission losses through the heat transmission loss factor $htlf_{hz}$.

$$q^{DH}_{t,y,hz} = (1 - htlf_{hz}) \cdot \left(\sum_{y-tlt<yy\leq y} \sum_{i\in H^{DH}} Q^{DH}_{i,t,y,yy,hz} + HS^{DH}_{t,y,hz} \right) \ \forall\ t, y, hz \tag{4.8}$$

Equation (4.9) illustrates the energy balance for individual heating, which is, moreover, accompanied by equation (4.10). The latter forces the hourly heat production, $Q^{IH}_{i,t,y,yy}$, of any technology aggregate $i \in H^{IH}$ to follow the general hourly dimensionless heat demand profile, $p^{IH}_{y,t}$, over the course of year y, when choosing a non-zero and positive yearly

production level, $L^{IH}_{i,y,yy}$. This ensures that the capacity of a certain technology, once installed, must be used in the short term and not other capacity instead. This constraint is necessary for individual heating, because a residential dwelling can usually rely on only one technology and is not able to create a technology mix in the short term. For instance, gas boiler capacity cannot be switched off at a specific time, when there is a demand in order to use instead, say, cheaper available electricity for heating and switched on in hours of scarce electricity. Hence, individual heat production has always to follow the demand profile. Consequently, if the production level is set to zero in a particular hour with an actual demand, this capacity's production level is always zero and is not allowed to produce in any hour.

$$q^{IH}_{t,y} = \sum_{y-tlt<yy\leq y} \left(\sum_{i\in CGU\cup OH^{IH}} Q^{IH}_{i,t,y,yy} \right) + HS^{IH}_{t,y} \qquad \forall\, t,y \tag{4.9}$$

$$Q^{IH}_{i,t,y,yy} = L^{IH}_{i,y,yy} \cdot p^{IH}_{y,t} \qquad \forall\, i,t,y,y-tlt<yy\leq y \tag{4.10}$$

4.2.4 CHP plants' and CU constraints

Constraint (4.11) limits the power output of CHP and CU to their maximum capacity.

$$G_{i,t,y,yy} \leq ava_i \cdot \overline{G}_{i,yy} \qquad \forall\, i \in CHP \cup CGU, t, y, y-tlt<yy\leq y \tag{4.11}$$

Back-pressure CHP plants and cogeneration units have a fixed ratio of power to heat output according to constraints (4.12) and (4.13). All CHP plants with two degrees of freedom, CHP^{PL}, such as extraction-condensation steam turbines or combined-cycles with extraction-condensation steam turbines and gas turbines with heat recovery boiler face power losses (PL), when providing heat. Their relation of power and heat output is described by constraints (4.14) and (4.15), whereas the power loss factor is determined by $\beta_{i,yy} = \frac{\eta^{CM}_{i,yy}}{\eta_{i,yy}} \cdot (1+\sigma_{i,yy}) - \sigma_{i,yy}$ for extraction-condensation CHP plants and $\beta_{i,yy} = 0$ for gas turbines with heat recovery boiler. Furthermore, as a consequence for any kind of newly installed CHP plant capacity the constraint $Q^{DH}_{chp,t,y,yy,hz} \leq \frac{\overline{G}_{chp,yy}}{\sigma_{chp,yy}+\beta_{chp,yy}}$ must hold.

$$G_{i,t,y,yy} = \sigma_{i,yy} \cdot Q^{DH}_{i,t,y,yy,hz} \qquad \forall\, i \in CHP^{BP}, t, y, y-tlt<yy\leq y, hz \tag{4.12}$$

$$G_{i,t,y,yy} = \sigma_{i,yy} \cdot Q^{IH}_{i,t,y,yy} \qquad \forall\, i \in CGU, t, y, y-tlt<yy\leq y \tag{4.13}$$

$$G_{i,t,y,yy} \geq \sigma_{i,yy} \cdot Q^{DH}_{i,t,y,yy,hz} \qquad \forall\, i \in CHP^{PL}, t, y, y-tlt<yy\leq y, hz \tag{4.14}$$

$$G_{i,t,y,yy} \leq \overline{G}_{i,yy} - \beta_{i,yy} \cdot Q^{DH}_{i,t,y,yy,hz} \qquad \forall\, i \in CHP^{PL}, t, y, y-tlt<yy\leq y, hz \tag{4.15}$$

Constraints for ramping as faced by CHP plants are not explicitly described here as there is no noteworthy difference to the plain version of dynELMOD.

4.2.5 Non-CHP constraints

Analogously to CHP plants, only heat generating technologies in district heating (OH^{DH}) (4.16) and individual heating (OH^{IH}) (4.17) are restricted to their maximum heat generation capacity. Heating technologies based on RES, such as solar-to-heat (S2H), are restricted by an hourly availability factor, $ava^{RES}_{i,t,y}$, changing according to weather conditions (4.18).

$$Q^{DH}_{i,t,y,yy,hz} \leq \overline{Q^{DH}_{i,yy,hz}} \qquad \forall\ i \in OH^{DH}, t, y, y - tlt < yy \leq y, hz \tag{4.16}$$

$$Q^{IH}_{i,t,y,yy} \leq \overline{Q^{IH}_{i,yy}} \qquad \forall\ i \in OH^{IH}, t, y, y - tlt < yy \leq y \tag{4.17}$$

$$Q^{IH}_{i,t,y,yy} \leq ava^{RES}_{i,t,y} \cdot \overline{Q^{IH}_{i,yy}} \qquad \forall\ i \in S2H, t, y, y - tlt < yy \leq y \tag{4.18}$$

Furthermore, constraint (4.19) ensures heat pumps in individual heating to be always equipped with some electric boiler capacity. This backup capacity is dimensioned by the heat pump capacity share, $hpcs$, based on Hedegaard and Balyk (2013).

$$\overline{Q^{IH}_{i,yy}} \leq \frac{hpcs}{1 - hpcs} \cdot \overline{Q^{IH}_{EB^{IH},yy}} \qquad \forall\ i \in ASHP^{IH} \cap GSHP^{IH}, yy \tag{4.19}$$

4.2.6 Heat storage

The model extension distinguishes between heat storage, same as TES (HS) for district heating (HS^{DH}) and individual heating (HS^{IH}). For both restrictions (4.20a)-(4.20c) hold. Large central heat storage for district heating are furthermore constrained by their charging and discharging capacity (4.20d) and (4.20e) respectively.

$$HS_{i,t,y} = HS^{D}_{i,t,y} - HS^{C}_{i,t,y} \qquad \forall\ i \in HS, t, y \tag{4.20a}$$

$$HS^{L}_{i,t,y} = \eta_{i,yy} \cdot HS^{L}_{i,t-1,y} + HS^{C}_{i,t,y} - HS^{D}_{i,t,y} \qquad \forall\ i \in HS, t, y \tag{4.20b}$$

$$HS^{L}_{i,t,y} \leq \sum_{y-tlt<yy\leq y} \overline{HS}_{i,yy} \qquad \forall\ i \in HS, t, y \tag{4.20c}$$

$$HS^{C}_{i,t,y,hz} \leq \sum_{y-tlt<yy\leq y} \overline{Q^{DH}_{i,yy,hz}} \qquad \forall\ i \widehat{=} HS^{DH}, t, y, hz \tag{4.20d}$$

$$HS^{D}_{i,t,y,hz} \leq \sum_{y-tlt<yy\leq y} \overline{Q^{DH}_{i,yy,hz}} \qquad \forall\ i \widehat{=} HS^{DH}, t, y, hz \tag{4.20e}$$

4.2.7 Emissions

Constraint (4.21) represents the strongest driver in limiting the use of fossil fuel in all power plants, CHP plants, and heat-only plants in the district heating supply by means of the yearly European CO_2 emissions budget, el_y. Note, individual heating is not constrained by this limit, since, up to now, this emission sector is not included in the European emission

trading system (ETS).

$$... + \sum_{t} \sum_{y-tlt<yy\leq y} \sum_{f} \sum_{i\in H^{DH}} cc_{i,f} \cdot F_{i,t,y,yy} \leq el_y \qquad \forall\ y \tag{4.21}$$

4.3 Data and assumptions

In order to properly examine the impacts of power and heat sector coupling five different scenarios are rolled out to juxtapose their results. As the reference serves the Power System-only (PS-only) scenario, which does not take any heating demand or technology into account. This helps to quantify the importance of incorporating or neglecting the heating sector. All other scenarios comprise the complete low temperature individual and district heating demand in Germany. Here two different exogenously determined heat demand developments are distinguished. In the Decreasing Heat Demand (DHD) scenarios, it is assumed that heat demand decreases until 2050 according to the political targets. They are successfully reached thanks to the realization of various energy efficiency measures, beneficial consumer behavior adjustments, and other heat energy consumption reductions. Opposed to them are the Constant Heat Demand (CHD) scenarios, which assume a pessimistic view, where no heat energy consumption reduction is achieved. Consequently, heat demand stays constant at 2015 levels. Furthermore, the Decreasing Heat Demand and the Constant Heat Demand scenario are further varied without power-to-heat (DHD w/o P2H and CHD w/o P2H) and with power-to-heat technology available (DHD and CHD). In the latter, this means that the power and heat sector are linked by CHP and power-to-heat technology, whereas in the former variation CHP is the only linkage. This setup of scenarios allows firstly, to show methodological differences of neglecting and incorporating the heat sector in a power system model. Secondly, it is methodological very difficult to make assumptions about future heat energy demands or costs for investments into heat energy reductions in order to determine these investments endogenously. Thus, this issue is addressed here by running a decreasing and a constant heating demand scenario. The hypothetical variations without power-to-heat serve for contrasting, how the power system would develop without having to cover substantial heat energy demand. Instead, they focus only on a more accurate modeling of CHP plants compared to the PS-only computation. Table 4.1 summarizes these scenarios and their features. The modeling objective in each scenario is to cover at lowest possible costs the power demand in all European countries and, additionally, the individual and district heating demand in Germany for each year under a yearly tightening CO_2 budget. Moreover, this happens in such a way that hourly power and heat loads are always met.

Computing the cross-sectoral power and heat model in dynELMOD+heat requires numerous input data and related assumptions about the power sector on the one hand and about the heat supply in Germany on the other hand. Since all input data and related assumptions concerning the power sector are already comprehensively documented in the data section of Gerbaulet and Lorenz (2017), this section provides only data required about Germany's heating sector. This data and its implementation in the model is freely

Table 4.1: Scenario overview.

Scenario	Abbreviation	DH incl. CHP/IH	P2H	Heat demand
Power System-only	PS-only	✘	✘	✘
Decreasing Heat Demand w/o P2H	DHD w/o P2H	✔	✘	decreasing
Decreasing Heat Demand	DHD	✔	✔	decreasing
Constant Heat Demand w/o P2H	CHD w/o P2H	✔	✘	constant
Constant Heat Demand	CHD	✔	✔	constant

accessible (Bloess, 2018). Recall that the heat sector add-on of dynELMOD+heat distinguishes between the individual and district heating supplies. In this respect, the section treats always both sectors separately and is subdivided into the sections heat demand, heat generation capacities, and technical progress.

4.3.1 Heat demand

Table 4.2 lists the assumed yearly demand for power and heat of Germany in the different scenarios under investigation as well as the available yearly European CO_2 emissions budget. The conventional power demand and CO_2 emissions budget are the same in all scenarios. Note, only heat generation of the district heating sector is constrained by the CO_2 emissions budget, which affects CHP plants and fossil-fueled heat-only plants. Emissions from individual heating do not exploit this CO_2 emissions budget, since these are currently not under the control of the European ETS. In the CHD and CHD w/o P2H scenarios, individual and district heating demand stay equal at the 2015 level until 2050. In the DHD and DHD w/o P2H scenarios however, they decrease according to the optimistic view that investments into energy efficiency and demand reductions take place in such a way that the political targets by the German Federal Government are finally met.

Historical data about total yearly demand of space (SH) and domestic hot water (DHW) heating in the sectors industry, services, and residential are obtained from BMWi (2017). Furthermore, yearly heat supplies of specific important district heating networks can be found either on the websites of the corresponding utility companies or already composed in the yearly reports by the German association for district heating, cooling and CHP (AGFW, 2015). Historical ambient temperatures in hourly resolution, $\vartheta^a_{t,y}$, are provided by the German Meteorological Service, which operates 78 weather stations across Germany (DWD, 2017). The hourly heat load is composed of a space heating load and a domestic hot water heating load. Note, that only the former is assumed to be temperature dependent and appears only within the heating season. Heat energy for DHW follows a standardized residential profile, p^{DHW}_t, derived from (Frederiksen and Werner, 2014, p. 55). The space heating load is calculated by use of heating degree hours for those hours within the heating season as shown in equation (4.22). Together with loads for DHW this adds up to the

Table 4.2: Yearly energy demand in TWh and European CO_2 emissions budget.

Demand	Scenario	Unit	2015	2020	2030	2040	2050
Exogenously:							
con. power	all	TWh_{el}	544	562	611	590	574
CO_2 emissions	all	Mt	1,273	965	598	270	19
DH	DHD/ DHD w/o P2H	TWh_{th}	69	62	48	35	21
DH	CHD/ CHD w/o P2H	TWh_{th}	69	69	69	69	69
IH	DHD/ DHD w/o P2H	TWh_{th}	710	644	510	377	244
IH	CHD/ CHD w/o P2H	TWh_{th}	710	710	710	710	710
Endogenously:							
P2H demand	DHD	TWh_{el}	End.	End.	End.	End.	end.
P2H demand	CHD	TWh_{el}	End.	End.	End.	End.	End.

hourly individual and district heating load in equations (4.23) and (4.24) respectively.

$$hdh_{t_h} = \begin{cases} 0 & , \vartheta^a_{t,2015} \geq 15\ [°C] \\ 20\ [°C] - \vartheta^a_{t,2015} & , \vartheta^a_{t,2015} < 15\ [°C] \end{cases} \qquad \forall\ t_h \tag{4.22}$$

$$q^{IH}_{t,y} = \frac{hdh_t}{\sum_{tt} hdh_{tt}} \cdot \overline{q^{IH,SH}_y} + p^{DHW}_t \cdot \overline{q^{IH,DHW}_y} \qquad \forall\ t \tag{4.23}$$

$$q^{DH}_{t,y,hz} = \frac{hdh_t}{\sum_{tt} hdh_{tt}} \cdot \overline{q^{DH,SH}_{y,hz}} + p^{DHW}_t \cdot \overline{q^{DH,DHW}_{y,hz}} \qquad \forall\ t \tag{4.24}$$

4.3.2 Heat generation technologies

The degree of detail in dynELOMD concerning existing and new capacities is equal in all represented European countries. The power generation technology assumptions as originally used in Gerbaulet and Lorenz (2017) are listed here in the appendix C.2. Only in terms of heating technologies is Germany represented with greater detail, because it is the only country in the model extension, whose heat energy demand is to be covered. Additionally, it is more detailed concerning the characteristics of different types of CHP capacities.

Table 4.3: Technology data in dynELMOD+heat.

		Technology/ Fuel	Overnight cost [€/kW]		Overnight storage capacity cost [€/kWh]	Fixed O&M cost [€/kW]		Variable O&M cost [€/MWh]		Efficiency (in condensation mode in EC CHP) [%]		Technical lifetime [years]	Economic lifetime [years]	Availability [%]	CHP & CU power-over-heat ratio σ [-]
			2015	2050	2020-2050	2015	2050	2015	2050	2015	2050	2015-2050	2015-2050	2015-2050	2020-2050
DH	CHP BP	lignite	2.070	2.070		63	63	7	7	80	90	40	30	85	0.8
		coal	2.070	2.070		53	53	6	6	80	90	40	30	85	0.8
		gas	633	633		16	16	3	3	80	90	40	30	85	0.8
		oil	460	460		6	6	3	3	80	90	40	30	85	0.8
		waste	2.788	2.244		105	105	8	8	80	90	50	30	80	0.8
		biomass	2.760	2.760		105	105	8	8	80	90	40	30	80	0.8
	CHP EC	lignite	2.160	2.160		63	63	7	7	75 (39)	85 (46)	40	30	85	0.9
		coal	2.160	2.160		53	53	6	6	75 (40)	85 (47)	40	30	85	0.9
		gas	660	660		16	16	3	3	75 (40)	85 (49)	40	30	85	0.9
		oil	480	480		6	6	3	3	75 (40)	85 (47)	40	30	85	0.9
		waste	2.909	2.341		105	105	8	8	75 (39)	85 (46)	50	30	80	0.9
		biomass	2.880	2.880		105	105	8	8	75 (39)	85 (46)	40	30	80	0.9
	GTCHP	GT gas	715	715		16	16	2	2	70 (34)	85 (41)	40	30	80	0.9
		CCBP gas	920	920		21	21	3	3	70 (60.2)	85 (61.9)	40	30	85	0.9
		CCEC gas	960	960		21	21	3	3	70 (60.2)	85 (61.9)	40	30	85	0.9
		GT oil	520	520		6	6	3	3	70 (34)	85 (41)	40	30	80	0.9
	F2H	lignite	343	343		17	17	0	0	88	88	40	30	100	
		coal	294	294		15	15	0	0	90	90	40	30	100	
		gas	130	130		7	7	0	0	95	98	40	30	100	
		oil	156	156		8	8	0	0	93	95	40	30	100	
		waste	490	490		25	25	0	0	86	86	40	30	100	
		biomass	490	490		25	25	0	0	86	86	40	30	100	
IH	F2H	old gas	546	384		21	21	0	0	97	97	25	20	100	
		condens. gas	438	308		21	21	0	0	104	105	25	20	100	
		old oil	836	588		45	45	0	0	92	95	25	20	100	
		condens. oil	772	543		41	41	0	0	99	105	25	20	100	
		biomass	1.673	1.177		6	6	0	0	72	95	25	20	100	
	CU	gas	2.593	1.824		130	91	0	0	85	85	25	20	100	0.65
		oil	2.593	1.824		130	91	0	0	85	85	25	20	100	0.65
	S2H	sun	1.173	691		5	5	0	0	100	100	25	20	100	
DH/IH	P2H	EB DH	202	202		0	0	0	0	99	99	40	30	100	
		EB IH	38	38		0	0	0	0	99	99	25	20	100	
		GSHP DH	2.909	2.046		145	102	0	0	100	100	40	30	100	
		ASHP IH	1.600	1.126		9	9	0	0	100	100	25	20	100	
		GSHP IH	2.400	1.688		9	9	0	0	100	100	25	20	100	
	TES	TES DH	900	900	9					95	95	40	30	100	
		TES IH			10					85	85	25	20	100	
transmission capacity expansion			1 €/(kW km)									50	50		

Source: Based on ASUE (2011) and own estimations.

Table 4.4: Fuel prices in dynELMOD.

in €$_{2013}$ per MWh$_{th}$	2015	2020	2030	2040	2050
uranium	3.20	3.40	3.80	4.20	4.60
lignite	4.80	5.21	6.03	6.85	7.67
hard coal	4.41	6.62	8.83	9.27	10.59
gas	18.54	25.60	28.69	31.78	33.10
oil	23.83	36.63	48.55	52.96	56.49
biomass	8.10	9.00	10.80	12.60	14.40
waste	8.10	9.00	10.80	12.60	14.40

Source: Capros et al. (2016)

DynELMOD+heat includes several different CHP plant types, fuel-to-heat plants and heat storage in the district heating supply. For individual heating, it comprises cogeneration units, fuel-to-heat facilities, solar thermal heating, and heat storage. Power-to-heat facilities are also available in both sectors. Table 4.3 summarizes all cost types for each heating technology, which are overnight investment, fixed operation and maintenance, and variable operation costs, as well as technical parameters, such as efficiency, technical, and economic lifetime, availability, and the power-to-heat ratio σ in case of CHP plants and cogeneration units. Extraction-condensation CHP plants (EC) and open-cycle gas turbines (GTs) with heat recovery boiler require two types of efficiency parameters for accurate modeling. For these technologies, Table 4.3 indicates the total fuel efficiency for the joint power and heat production at maximum heat output. Additionally, in brackets, it indicates the condensation mode (CM) efficiency, that is when this type of CHP plants produce only power and, hence, are operating like conventional power plants. Note that existing CHP plants are implemented block sharp, whereas newly installable CHP capacities and all other existing and newly installable technologies are implemented as technology aggregates. Moreover, Table 4.4 illustrates the assumed price developments for fuels in dynELMOD+heat.

The estimates for existing non-CHP heating capacities and their development is illustrated by Figure 4.3. It is assumed that all technologies existing in 2015 are decommissioned by 2040, at the latest.

4.3.3 Technical progress

Over the 2020-2050 investment horizon, technical progress that affects immature technologies in terms of investment cost reductions and efficiency improvements is assumed. Both are indicated in Table 4.3 by showing values of 2015 and 2050. Figure 4.4 shows the investment cost reduction path in more detail for selected technologies.

Investments into, and operation of, heat pump capacity is crucially dependent on its consumption of electric energy. This is determined by its coefficient of performance (COP), indicating how many units of heat can be provided by using one unit of electricity. As previously outlined, the coefficient of performance is determined by two factors: the Carnot-

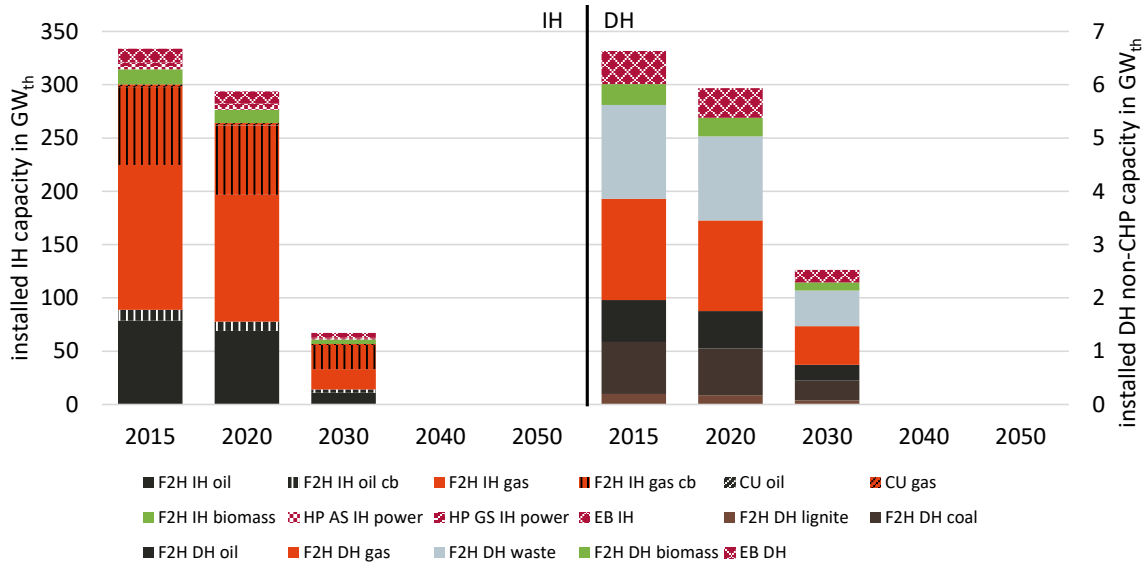


Figure 4.3: Development of existing individual heating (IH) capacity and district heating (DH) non-CHP capacity.

Source: Own depiction.

COP and the heat pump quality grade $\omega_{i,yy}$, which is subject to technical progress. Figure 4.5 indicates the resulting coefficient of performance and its technical progress with a generic lower level vintage in 2015 and an upper level of the 2050 vintage for the heat pump types considered in dynELMOD+heat. Note, only air source heat pumps are dependent on ambient air temperature variations. The heat source temperature of ground source heat pumps is assumed to stay constant.

4.3.4 Additional constraining assumptions

If there were abundant biomass resources available, fossil fuels in the heating sector could be easily substituted with CO_2 neutral biomass fuels. Nevertheless, their access is limited and this is accounted for by means of constraint (4.25), where ... stands for all biomass-fueled power generation already covered by the power-only model (Gerbaulet and Lorenz, 2017).

$$\ldots + \sum_{i \in H^{biomass},t} F_{i,t,y,yy} \leq \overline{f_y^{biomass}} \; \forall \; y, y - tlt < yy \leq y \tag{4.25}$$

Some additional constraining assumptions are necessary to influence results of existing capacities for more plausibility. Since the heat supply is always based on the local distribution infrastructure with only specific heat generation facilities available, there is technically no technology mix possible. This stands in contrast to the power sector, where in reality even far distant technologies with lowest variable costs are primarily employed. A linear model with aggregated heat demand and aggregated technologies composes such a tech-

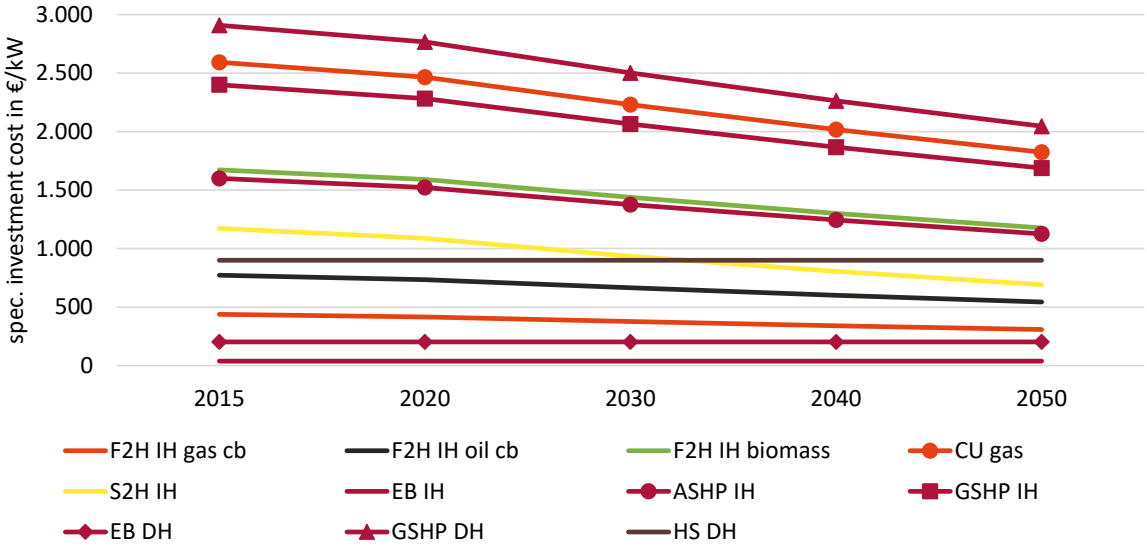


Figure 4.4: Development of specific investment costs of selected technologies.

Source: Own depiction.

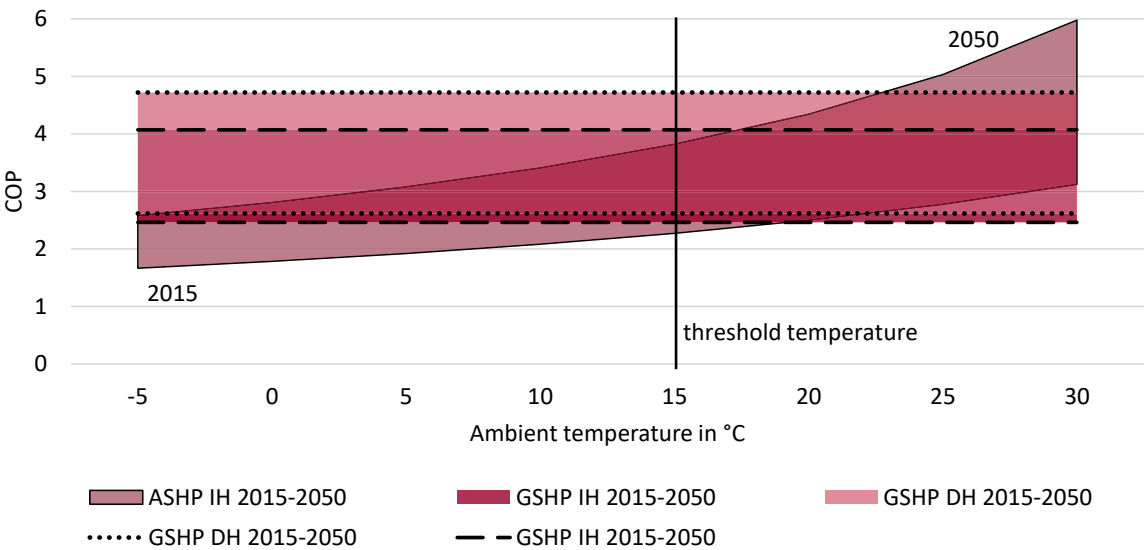


Figure 4.5: Technical progress of heat pumps' COP and its dependence on ambient temperature.

Source: Own depiction.

nology mix leading to favor dominant technologies in terms of costs and efficiency vintage. This happens even though certain less dominant technologies must be employed in reality, because they might be the only locally available facility. Hence, constraint (4.26) ensures a more plausible usage of standing capacity by a minimum yearly production in proportion to the installed capacity shares of existing CHP plants in district heating supply. Constraint (4.27) ensures the same for existing fuel-to-heat and cogeneration facilities in individual heating.

$$\sum_t Q^{DH}_{i,t,y,yy,hz} \geq cs^{CHP}_{i,y} \cdot \frac{\sum_t q^{DH}_{t,y,hz}}{1 - htlf_{hz}} \qquad \forall\ i \in CHP, hz, y, y - tlt < yy \leq y \tag{4.26}$$

$$\sum_t Q^{IH}_{i,t,y,yy} \geq cs^{IH}_{i,y} \cdot \sum_t q^{IH}_{t,y} \qquad \forall\ i \in F2H^{IH} \cup CGU, y, y - tlt < yy \leq y \tag{4.27}$$

Furthermore, constraint (4.28) ensures that in individual heat production, the ratio of production fueled by oil to production fueled by gas stays in the proportion of the 2015 capacity ratio of these two energy carriers. This is based on the assumption that facilities fueled with oil cannot easily obtain access to a gas supply infrastructure.

$$\sum_t \sum_{i \in H^{IHoil}} Q^{IH}_{i,t,y,yy} \geq \frac{\sum_{i \in H^{IHoil}} \overline{q^{IH}_{i,2015}}}{\sum_{i \in H^{IHgas}} \overline{q^{IH}_{i,2015}}} \cdot \sum_t \sum_{i \in H^{IHgas}} Q^{IH}_{i,t,y,yy} \qquad \forall\ y, y - tlt < yy \leq y \tag{4.28}$$

4.4 Results

The impact of heat sector transformation due to future expansion of power-to-heat on Germany's power system is presented here by first showing the potential power demand increase owing to power-to-heat. In the following, its effects on the development of power generation and storage capacity as well as the actual energy generation are shown. Lastly, the same is also presented for the individual and district heating supplies. Results focus here only on Germany. However, Germany is embedded into the European electricity market. In order to see the full picture and have a better base for interpreting results, it is necessary to furthermore show model outcomes concerning cross-border trade and transmission capacities as well as aggregated differences in power capacities and generation of other European countries.

4.4.1 Electric energy demand development

Due to an increasing use of electric energy for heating the total demand for electric energy necessarily rises. Figure 4.6 illustrates this demand development. The conventional electric energy demand is exogenously determined and equal in all scenarios. According to the assumptions described in Section 4.3, Germany's yearly conventional net electric energy demand starting from around 540 $\mathrm{TWh_{el}}$ in 2015 is expected to peak around 2030 with over 610 $\mathrm{TWh_{el}}$ in 2030 before continuously decreasing until 2050. The Decreasing Heat

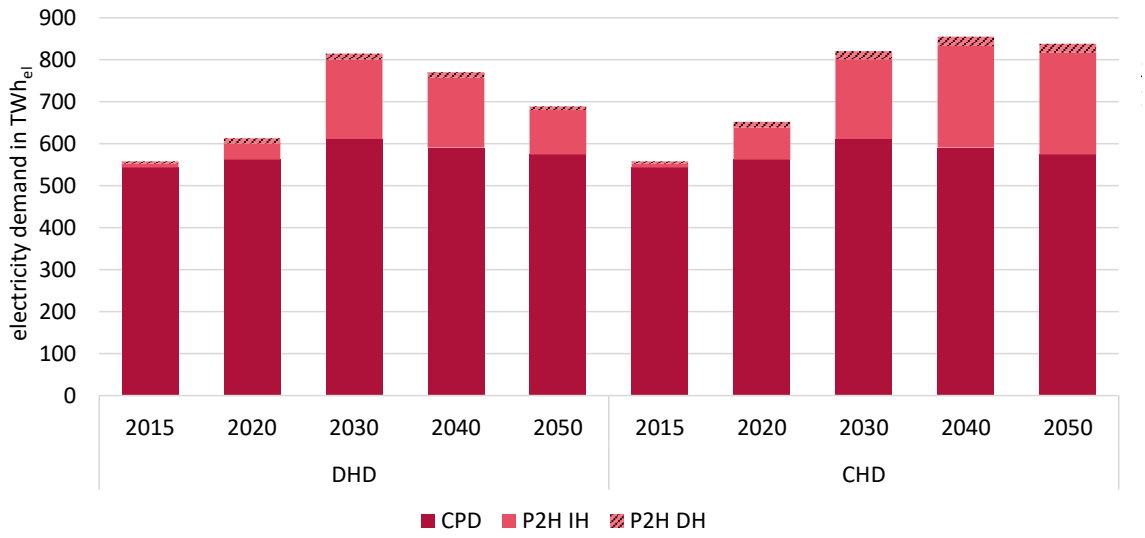


Figure 4.6: Electric energy demand development with additional power-to-heat demand.

Demand scenario (DHD) indicates an additional electric energy demand for employing power-to-heat technologies, which is determined endogenously by the model. This demand also peaks in 2030 at more than 200 TWh$_{el}$ and decreases significantly to nearly 110 TWh$_{el}$ in 2050 thanks to lower space heating demand and technical progress of heat pumps. This extra consumption is driven mainly by the individual heating sector accounting for more than 90% between 2030 and 2050. In the Constant Heat Demand (CHD) scenario, additional electric energy demand increases sharply to over 260 TWh$_{el}$ in 2040 and remains stable, even in 2050. Here the additional demand is nearly completely dominated by the individual heating sector. Hence, both power-to-heat scenarios show a substantial rise in electric energy demand to 200–260 TWh$_{el}$ in peak years and to 110–260 TWh$_{el}$ in the long run in 2050. Comparing this to other studies as mentioned in Section 4.1, such increase appears rather modest, when also including other new power consumption sectors, such as electric mobility or power-to-fuels. However, opposing this only to low temperature heat consumption, the increase to 110 TWh$_{el}$ in 2050 in the DHD scenario is in line with those studies. In contrast, the conservative assumption of the CHD scenario shows an upper bound of extra electric energy demand that is two and a half times as high as in those that allege substantial energy consumption reductions.

4.4.2 Power sector's capacity and generation development

Figure 4.7 illustrates Germany's development of installed electric generation capacities. All sector-coupling scenarios considering power-to-heat show significantly higher and earlier capacity installations for wind power than the Power System-only (PS-only) scenario. The latter shows a maximum expansion of wind power capacity in 2050 of 130 GW$_{el}$. In the DHD scenario, this is surpassed already in 2030, reaching nearly 160 GW$_{el}$ in 2050. The

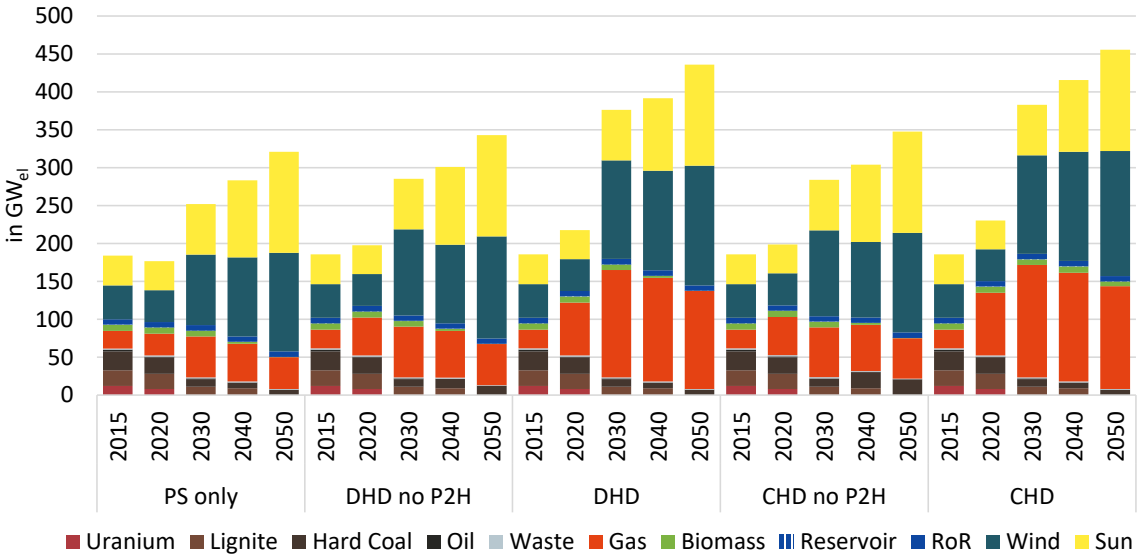


Figure 4.7: Germany's power generation capacity development.

CHD scenario shows similar developments with just slightly more installation of nearly 165 GW_{el} in 2050. The scenario variations without power-to-heat, DHD w/o P2H, and CHD w/o P2H, show nearly the same wind capacity expansions as in the PS-only scenario. The development paths of PV capacity reaching around 135 GW_{el} in 2050 are nearly the same in all scenarios and rather lower in the power-to-heat scenarios before 2050. Therefore, power-to-heat technology rather favors the expansion of wind power over PV capacity. This can be explained by the fact that heating is mainly required in winter season, when capacity factors for PV are comparatively low. Higher capacity factors for PV appear naturally in summer time, but are less utilizable then. Hence, PV, in contrast to wind production, behaves anti-cyclical to the additional power demands through power-to-heat and is not at all driven by it.

Looking additionally at Germany's power generation development in Figure 4.8, also reveals the growing domination of wind generation and its bigger role compared to PV generation. Wind generation expands from 340 TWh_{el} in the PS-only scenario in 2050 to 420 TWh_{el} and 430 TWh_{el} in the DHD and CHD scenarios, respectively. Remarkable here is the role of gas-fueled power capacity and generation. Whereas the gas-fueled capacity development in the scenarios DHD w/o P2H and CHD w/o P2H is rather similar to the development in the PS-only scenario, there are important expansions observable in the power-to-heat scenarios DHD and CHD with 130 GW_{el} and 135 GW_{el} respectively in 2050, compared to about 40 GW_{el} in the PS-only scenario. These capacities mainly stem from combined-cycle (CC) and open-cycle (GT) gas turbine installations and will have already declined compared to their peak expansion in 2030. In the actual electricity generation, gas becomes the strongest fossil energy carrier. However, compared to wind power generation, its role stays minor. For some conventional power generation technologies, the

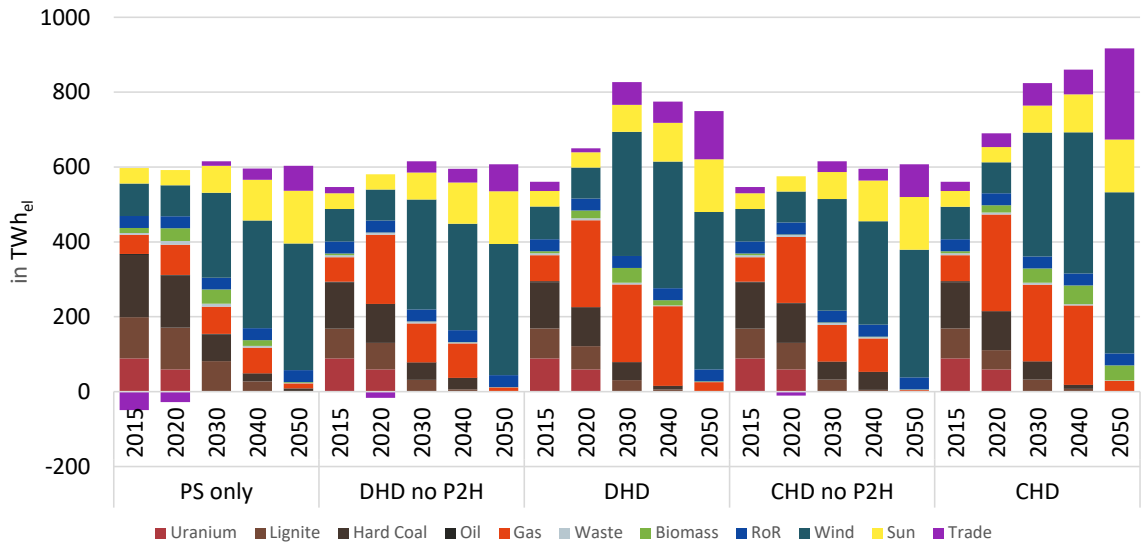


Figure 4.8: Germany's power generation development.

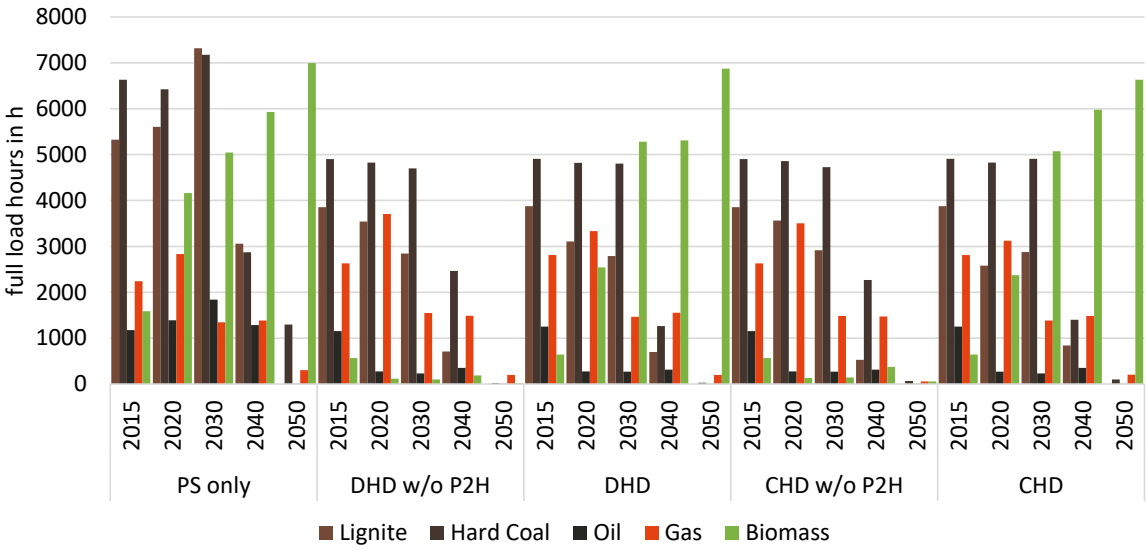


Figure 4.9: Development of full load hours of selected fuels for power generation in Germany.

development of installed capacity and actual employment go different directions. This is illustrated by the full load hours for selected fuels in Figure 4.9. Generation capacities fueled by lignite, hard coal, and oil show significantly faster decreasing full load hours in the sector coupling scenario than in the PS-only scenario. Only biomass-fueled capacities show similar full load hours compared to the PS-only scenario, when also power-to-heat is involved. Yet, in the scenarios without power-to-heat, full load hours go nearly to zero, because the limited availability of biomass is rather used for a fuel switch in heating, as seen in Section 4.4.5. In contrast, the full load hours of gas-fueled technologies increase for 2015 and 2020 before decreasing with the same amounts as in the PS-only scenario. Its low capacity factors of around 17% in 2040 dropping to less than 3% in 2050, classifies these installations as backup and peak-load capacities. The extreme drop in generation from 2040 to 2050 is explained by the emission constraint, which barely allows any emissions in 2050. Additionally, noteworthy here is the observation that it is the gas-fueled power-only technologies that dominate the conventional expansion; gas-fueled CHP plants barely come into appearance. This fact is explained by the notion that for times of low renewable energy availability, the model chooses as alternative to renewable power for heating the combination of highly efficient combined-cycle gas turbines with heat pumps. This technology combination shows significantly higher flexibility and efficiency than CHP plants.

Furthermore, Figure 4.10 gives insights into how the additional demand through power-to-heat is covered. It shows the most important differences of yearly aggregated sources of generation in the DHD and CHD scenario to the PS-only scenario. According to that, the additional generation in 2020 comes primarily from gas-fueled generation and increases in imports in both scenarios. Between 2030 and 2050, important shares of wind power generation are added as a major source; however, gas-fueled generation is the biggest source to cover the additional demand in 2030 and 2040. Only in 2050, as mentioned above, gas-fueled generation drops heavily and the additional demand is only covered by wind power and imports in the DHD scenario. The even greater demand in the CHD scenario in 2050 is covered additionally by some generation fueled by biomass and even larger imports. The reductions of power generation based on lignite and coal must be partly attributed to power-to-heat as well as to a different modeling technique concerning CHP generation in dynELMOD (which computes the PS-only scenario) and dynELMOD+heat. In the former model, exogenously determined minimum capacity factors for CHP plants simulate must-run capacities. The model extension dispatches CHP plants endogenously by freely choosing between alternative plants and technologies to cover district heating demand.

4.4.3 Interaction with surrounding countries

Recalling that the model computes the entire European power dispatch, effects through power exchanges with surrounding countries also have to be taken into consideration to better understand the model's outcomes. Consequently, Figure 4.11 illustrates Germany's trade activities in more detail and Figure 4.12 the development of interconnector capacity with its surrounding countries, which enables these cross-border flows.

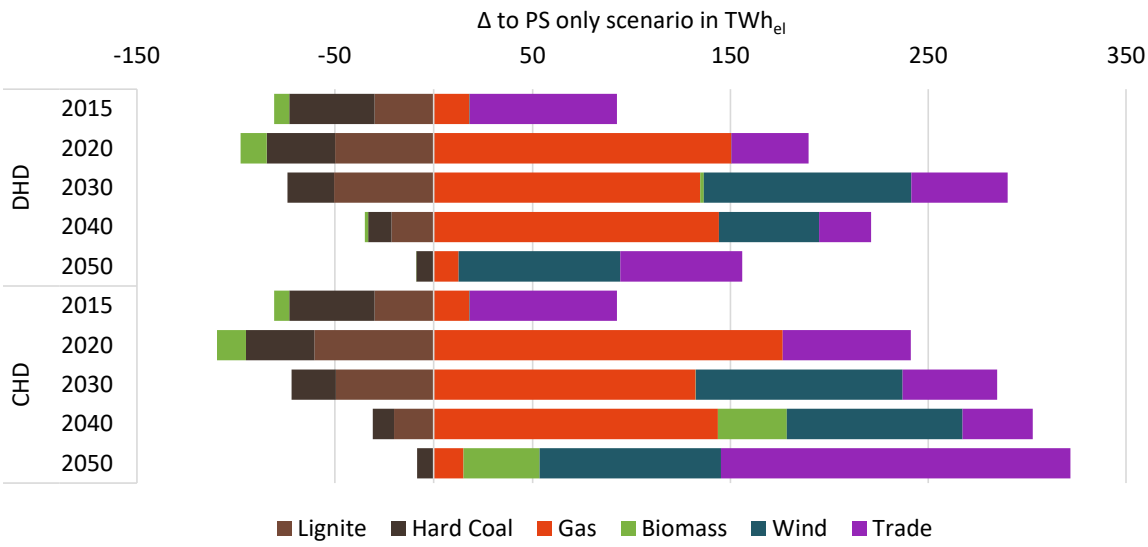


Figure 4.10: Differences of generation sources in Germany in power-to-heat scenarios compared to the PS-only scenario.

Germany shows electric energy net exports in 2015 and 2020 in the PS-only scenario. All other years and scenarios present Germany mainly as a net importer of electric energy with increasing amounts through 2050. The import and export differences in 2015 and 2020 between the PS-only scenario and the no power-to-heat scenarios result from different CHP modeling techniques as previously mentioned. In all other years, the imports in scenarios without power-to-heat appear similar to the PS-only scenario, but are higher, when power is employed as heating fuel. Except the CHD scenario displays in 2050 a substantial import being about 170 TWh$_{el}$ higher than in the PS-only scenario. The same holds for interconnector capacity development. Its capacity increase stays limited in the DHD and CHD scenarios compared to the PS-only scenario. Except, again, in 2050 in the CHD scenario, where the interconnector capacity increases strongly and is about 23 GW$_{el}$ higher than in the PS-only scenario, since imports become important here to fulfill very tight emission constraints in the last period. When power-to-heat technology is suppressed, interconnector capacity is not different to the PS-only scenario.

Overall, it can be concluded, that the additional demand for power due to power-to-heat is rather addressed by investments taking place in Germany and effects resulting from exchanges with other countries stay limited throughout the long term time horizon. Only the last modeling period in the CHD scenario is an exception. Furthermore, this observation is supported by analysing the power capacity and generation developments in all other countries than Germany. Figures 4.13 and 4.14 show the most important differences of capacity and generation developments in these countries compared to the PS-only scenario, respectively. The strongest differences are found in the CHD scenario in 2050 with around 60 GW$_{el}$ more wind and nearly 35 GW$_{el}$ more PV capacity amounting to around additional 145 TWh$_{el}$ and 30 TWh$_{el}$ of power generation, respectively. Apart from this latter

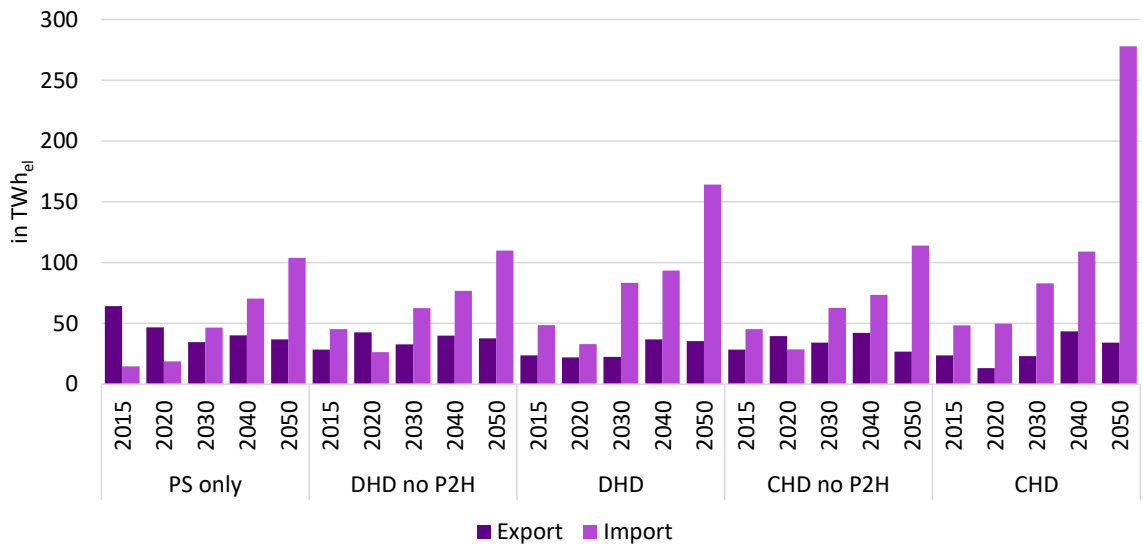


Figure 4.11: Germany's power trade exchanges.

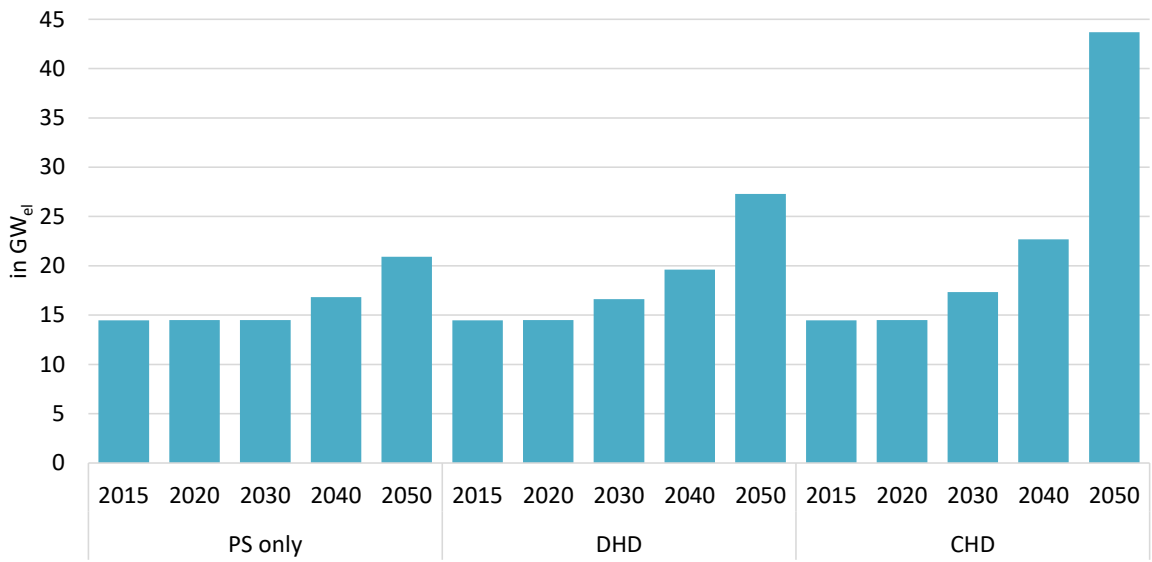


Figure 4.12: Germany's interconnector capacity development.

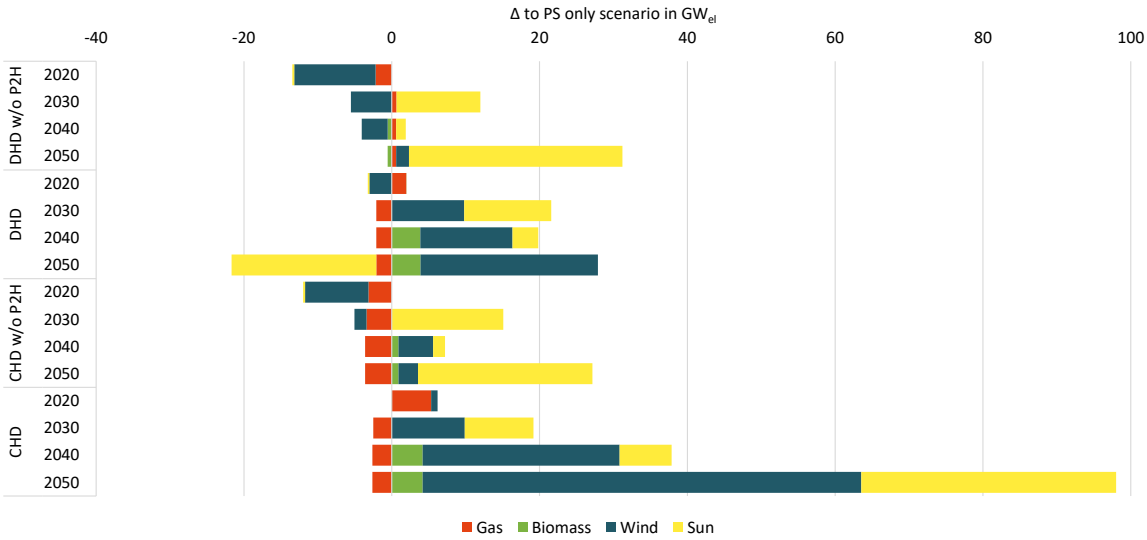


Figure 4.13: Differences of power capacity development compared to the PS-only scenario in all other European countries.

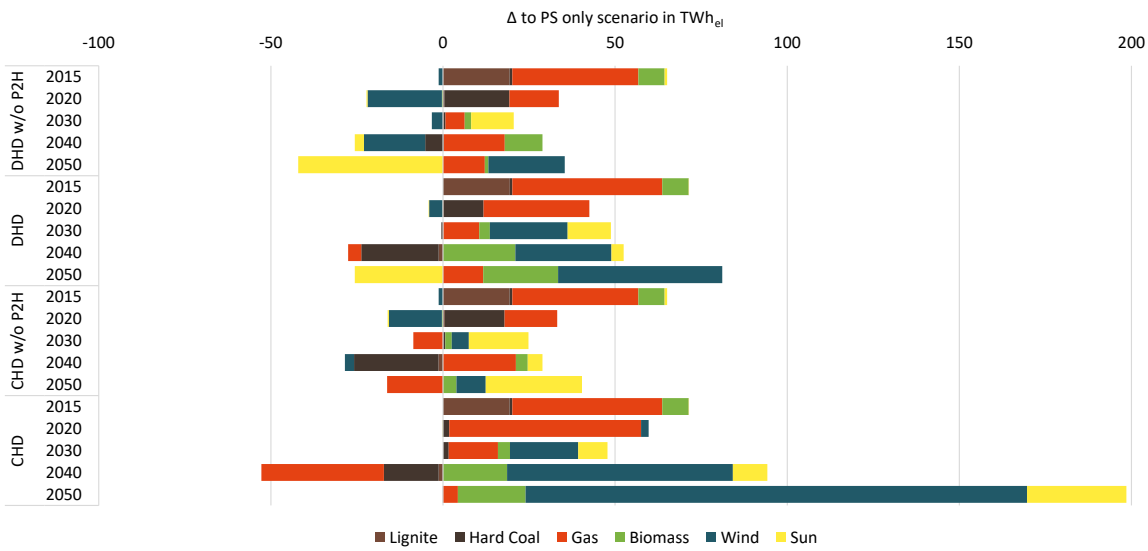


Figure 4.14: Differences of power generation development compared to the PS-only scenario in all other European countries.

difference, all other deviations in capacity and generation do not contribute substantially, considering the dimension of the entire European power capacity and generation.

4.4.4 Power and heat storage development

Figures 4.15 and 4.16 show the installation of charging/discharging capacity and energy volume of storage technologies in stacked column charts separated for power and heat storage. Recall from Section 4.2 that the model endogenously determines the charging/discharging capacity of any storage technology and its storable energy volume independently from each other. Hence, the ratio of storage size to charging/discharging capacity is freely determined. The only exception here is power-to-gas storage, where storage size is technically unlimited and available without extra costs. The strongest developments show batteries and power-to-gas capacities. In the PS-only scenario, battery capacity rises to about 35 GW_{el} with 230 GWh_{el} storage volume in 2050. Power-to-gas capacity appears only late in 2050 with a conversion capacity of 25 GW_{el}. In the DHD and CHD scenarios, the expansion of battery capacity and storage volume is lower with 16 GW_{el} capacity and 84 GWh_{el} storage and 20 GW_{el} and 124 GWh_{el}, respectively. Power-to-gas conversion capacity reaches finally 50 GW_{el} and 70 GW_{el} in the scenarios, respectively. In contrast to the PS-only scenario, where battery capacity is 9 GW_{el} higher than power-to-gas in the final period, power-to-gas outperforms battery expansion in 2050 with a difference of 36 GW_{el} in the DHD and 50 GW_{el} in the CHD scenario. Comparing to the w/o P2H scenario variations this difference is only moderate. In these scenarios, battery capacity and storage expansion is higher than in the power-to-heat scenarios, but lower compared to the PS-only scenario in the case of DHD w/o P2H. This demonstrates the inflexible CHP minimum load generation, as modeled in the PS-only scenario, requires more flexible storage capacity. Power-to-gas capacity develops in a similar way to the PS-only scenario. Concerning the other electricity storage technologies, there are no significant differences observable. There is no need for short-term DSM capacity and only moderate need for mid- and long-term DSM capacity (DSM12 and DSMLT), amounting in all scenarios to a level in 2020 and constant thereafter of 2 GW_{el} capacity for each with a storage volume of 2 GWh_{el} for the former and 12 GWh_{el} for the latter. Note that pumped storage plantss and hydro reservoirs are assumed to be at their maximum expansion level already and, hence, their capacity and storage volume are not expandable.

In summary, power-to-heat technology can significantly reduce the need for battery capacity and storage volume by nearly 40% in the last period comparing the DHD scenario to the PS-only scenario, since power surpluses over the conventional electric energy demand can be directly utilized in the heating sector (Zerrahn, Schill, and Kemfert, 2018). Although the CHD scenario shows a similar battery expansion path as the DHD scenario, the expansion of power-to-gas capacity is substantially higher in the last period. Actually, it could be expected that the need for power storage is similar or even lower, since a generally larger heat demand could directly absorb or store more surplus power in the form of heat. However, since electricity is so dominating as energy carrier for heating purposes in the later years in the DHD and CHD scenarios, the flexibility potential is

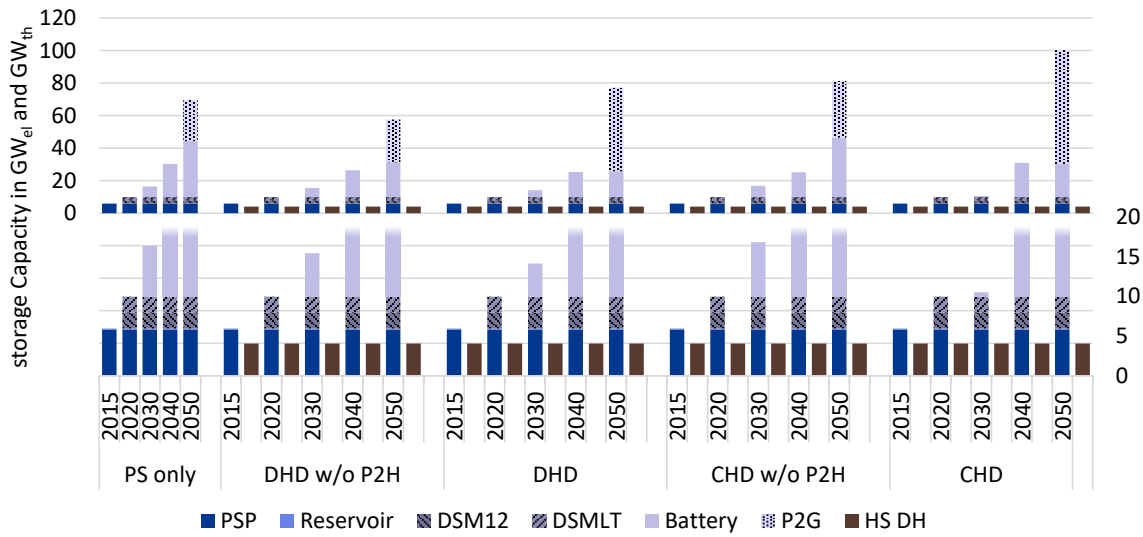


Figure 4.15: Storage charging/discharging capacity development.*

* Capacity for heat storage in the individual heating supply (HS IH) is not indicated, since they are assumed to be completely chargeable or dischargeable within an hour as small dispersed units, which is not computable in a model of hourly resolution.

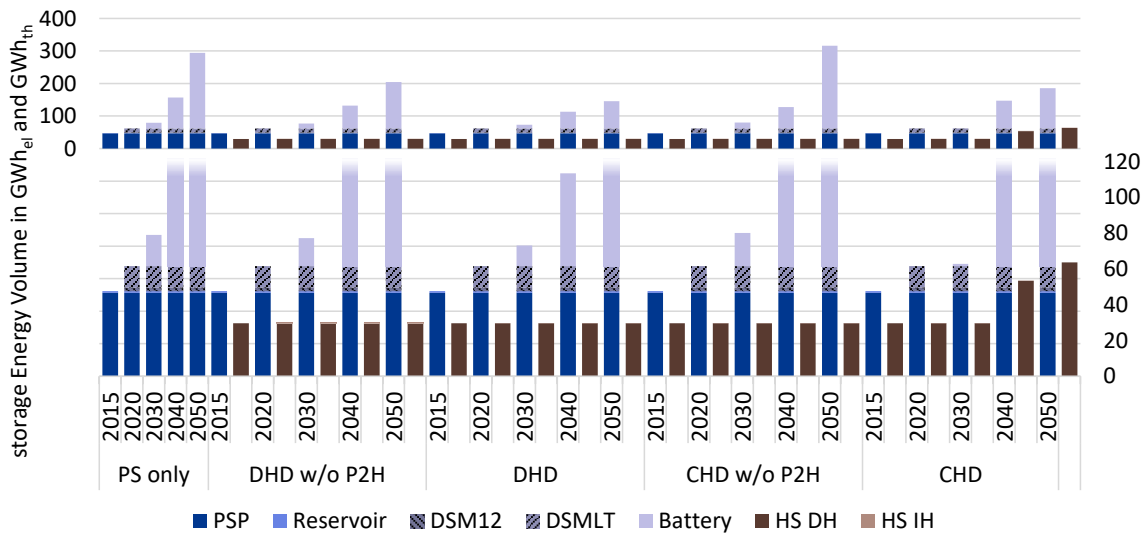


Figure 4.16: Storage energy volume development.*

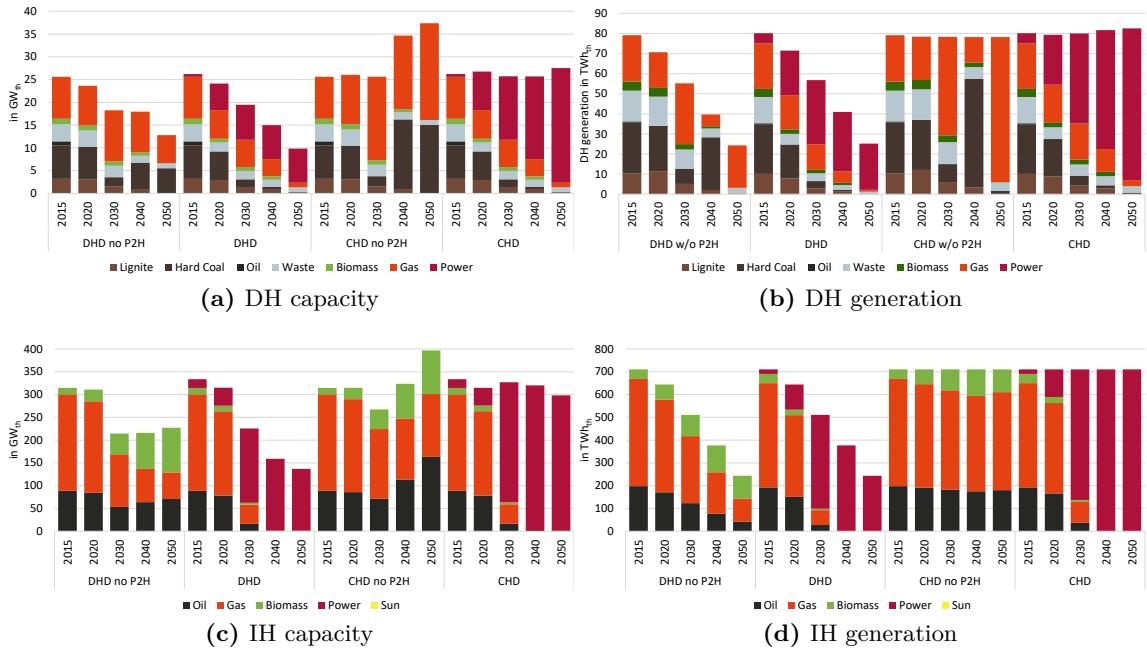
* The energy volume of power-to-gas technology is not indicated, since it is assumed to be effectively unlimited in the existing gas transmission infrastructure.

equally completely exploited in both heat demand developments. Consequently, greater heat demand does not provide greater potential flexibility here. The even higher heating demand of the CHD scenario just causes an even generally higher level of installed wind power capacity as well. This, in turn, makes more seasonal storage volume necessary in the CHD scenario. The downsizing of the heat demand allows, firstly, lower expansion of power-to-gas capacity, but battery storage is not reduced further due to this. Recall that battery storage is strongly advantageous over power-to-gas in terms of cycle-efficiency and specific investment cost of capacity. Yet, with the latter technology, storage volume comes at zero costs. Consequently, with the availability of power-to-heat as an effective short-term alternative to batteries for power surpluses, investments into power-to-gas as long-term storage become more favorable. Batteries might have a high cycle efficiency, but they are costly. When the need for short-term charging and discharging activities becomes less frequent, then low-cost long-term storage is more important.

The charging and discharging capacity for heat storage in district heating stays constant at around 4 GW_{th} regardless to the scenario. The same holds for its storage volume, except in the CHD scenario, where the initial volume of 30 GWh_{th} starts expanding in 2040 and more than doubles to 64 GWh_{th} in 2050. The individual heating sector does not show any requirement for heating. However, note that all heating technologies in this sector, such as fossil-fueled boilers, electric boilers, and heat pumps, are very flexible in terms of the time resolution applied in the model and independently from each other. Therefore, the actual need for storage may or may not exist. Consequently, it cannot be shown that significantly cheaper costs for heat storage compared to power storage lead to a stronger deployment of the former technology.

4.4.5 Heat sectors' capacity and generation development

Figure 4.17 summarizes developments in the district and individual heating sectors. Figures 4.17a and 4.17b; and Figures 4.17c and 4.17d display the thermal capacity and generation development in the district heating and individual heating sector, respectively. Concerning district heating supply, the sector shows a dramatic transformation to the use of power-to-heat technology. Figure 4.18 illustrates which specific power-to-heat technologies comprise this transformation. It clearly reveals an emphasis on ground source heat pumps and some additional electric boiler capacity. As displayed in Figure 4.17b, in the DHD scenario power-to-heat would dominate from 2030 on and would then replace nearly all other conventional heat generation until 2050. This holds in the same way for the CHD scenario, where the heat demand stays until 2050 at the high level of 2015. It could be argued that such domination of power-to-heat in district heating would not be justified due to relatively high heat transmission losses compared to power transmission and would rather lead to an abolition of district heating. However, technical progress and economies of scale in accessing ground source heat energy can allow substantially more efficient heat pumps compared to individual electric heating. Only when power-to-heat technology is suppressed, like in the DHD w/o P2H scenario, does coal-fueled heating in back-pressure CHP plants experience a revival in 2040 and is finally phased-out in 2050 and replaced by



(a) DH capacity **(b)** DH generation

(c) IH capacity **(d)** IH generation

Figure 4.17: Heat capacity and generation development in the district heating (DH) and individual heating (IH) sectors.

gas-fueled heat-only plants. In the CHD w/o P2H scenario, this generation expansion is about two times stronger. Since the CO_2 emissions constraint imposed by the emission budget is extremely tight in 2050, the model renounces on the operation of fairly newly installed coal CHP plants most of the time in the last year. Instead, about 5 and 20 GW_{th} new gas boiler capacity is installed in the DHD w/o P2H and CHD w/o P2H scenario, respectively, in order to force a low emission fuel switch and to provide very flexibly nearly all district heating energy.

Figures 4.17c and 4.17d illustrate developments in the individual heating supply, which is the main driver for increased power demand through its use as heating fuel. The DHD scenario reveals a determined decrease of oil and gas-fueled heating. In 2030, power-to-heat already dominates the heating supply and covers the demand completely in 2040 and 2050. The same holds for the CHD scenario at constant heat demand level. Recall that the individual heating sector is not constrained by the CO_2 emissions budget. The strong endogenously determined transformation to 100% heating by means of power-to-heat can only be explained by reduced curtailment of RES, lower expenditures for costly flexibility alternatives, such as power storage or DSM, and fairly low power generation costs through wind power and PV. Noteworthy as well is a major difference between the DHD and CHD scenario concerning the specific power-to-heat technology employment, which is shown by Figure 4.18. Whereas all power-to-heat is dominated by air source heat pump in the DHD scenario from 2030 on, in the CHD scenario the means of choice are mainly ground

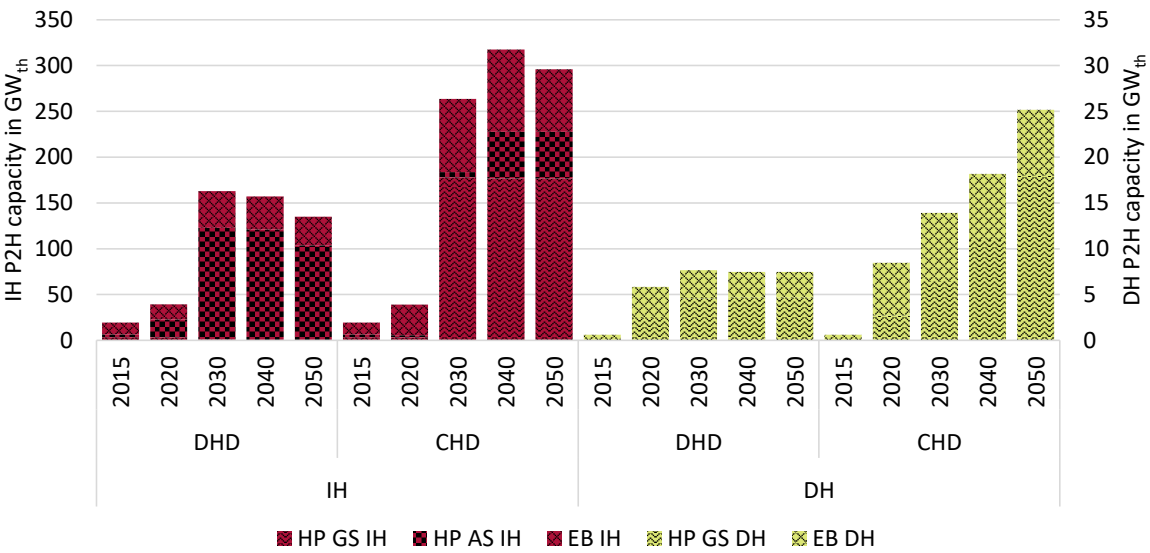


Figure 4.18: Thermal capacity development of power-to-heat technologies in Germany.

source heat pumps. The no-power-to-heat variations show a greater mix of oil, gas and biomass-fueled heating. No investments into solar-thermal heating are observed.

4.5 Discussion

An irregularity in the methodology could be seen in the fact that while the entire European power market is modeled, only the heating energy of Germany is modeled. Potentially, this could lead to distortions, where the demand for electricity is significantly increased through power-to-heat in a single country as important as Germany in terms of energy demand. There are two major approaches to address this problem. On the one hand, one could downsize the problem and model only the power and heat sector of Germany. However, also this approach would be highly controversial: since Germany's power market is integrated with surrounding countries, with constant economic exchange, many flexibility mechanisms resulting from cross-border trade would be completely neglected. On the other hand, one could go in the other direction and also model the local heating sectors in other countries as well. This would certainly be the most adequate approach. However, this is left for future research since the computational effort for this current version of dynELMOD+heat is already enormously challenging. Nevertheless, it is important to keep in mind that the degree of detail in terms of available technologies is higher for Germany compared to all other countries in the current model version of dynELMOD+heat. This leads to increased power exchanges of the other countries with Germany, since in the model they tend to make use of some of Germany's higher flexibility potential. By presenting the model's outcomes in terms of traded power, interconnector capacity and differences in the development of power capacity and generation in the other European countries compared to the PS-only scenario, the author aims to provide all the necessary information for judging the dimensions of this

methodological drawback and concludes that the irregularity is tenable.

Another methodological critique could be the fact that demand and supply side for heating are completely aggregated here for district and individual heating. This could lead to a heat generation mix that is actually not possible in locally isolated supply networks, unlike in the supraregional power sector characterized by substantially lower transport costs in comparison with district heating networks. Nevertheless, this critique can be alleviated in two ways. First, concerning district heating, the commonly alternative approach would be to assign minimum generation levels to CHP plants. This method however would neglect the degrees of freedom provided by other heating technologies, such as heat-only plants, storage, and power-to-heat. Second, in a linear modeling framework the aggregation affects only the existing plants and technologies, with the tendency to leave older vintages with lower efficiency idle. This issue is addressed here with the annual auxiliary constraints (4.26) and (4.27) for district and individual heating, respectively. In the short-term perspective, this issue is also addressed by constraint (4.10) for the supply side of individual heating. With these precautions, especially concerning new capacity installations, it is then irrelevant in a linear model to either invest into capacities assigned to several smaller heating demands or to a single large demand. Certainly, the computational efforts are significantly lower in the latter approach, thanks to fewer variables and equations.

To the best knowledge of the author, there is currently no dynamic long-term power and heat sector coupling model able to illustrate a transformation path from the current rather separated markets to a future integrated energy system for linking all European countries over a single electricity market. Consequently, future works for dynELMOD+heat should focus on expanding the heat sector add-on to the other European countries. This will also require restructuring and improvements to reduce computation efforts. This could be achieved by abandoning block sharp solving of power plants. However, it then becomes necessary to find an adequate methodology for the correct cost modeling of the joint output production of combined heat and power plants.

4.6 Conclusion

In a comprehensive energy policy, heating supply in Germany should get the same attention as the power sector gets regarding its share in final energy consumption and its contributions to greenhouse gas emissions. Since biomass as zero CO_2 emissions fuel has a limited availability and, hence, cannot be expected to sufficiently decarbonize the heating supply, electricity based on renewable energy sources plays a key role in this transformation. Furthermore, interactions between the two energy sectors through increased power and heat sector coupling can help to integrate renewable energy sources in both sectors. Sector coupling provides additional flexibility, when dealing with short-term variations in availability of wind and solar power. In order to analyze the long-term development of the German power system and heating supply, as well as their interactions through sector coupling technologies, such as CHP and power-to-heat, a new analysis tool is elaborated here: the extension of the dynamic power sector model dynELMOD to the German heat sector. The major novelty of dynELMOD+heat consists of the combination of a dynamic

long-term view through 2050 starting from the present 2015 energy system and the simultaneous covering of the German individual and district heating demand in conjunction with the German power demand and supply embedded into the European electricity market. It contains a rich set of diverse power and heat technologies with freedom of choice concerning the dispatch, that is how to meet short-term power and heat demands, as well as investment decisions over a long-term horizon through 2050 under a tightening yearly European CO_2 emissions constraint.

The results reveal that electricity is becoming an increasingly important energy carrier for heating purposes. In the optimistic Decreasing Heat Demand scenario, where important reductions of heat energy consumption are assumed, as well as in the pessimistic Constant Heat Demand scenario, where these reductions are not assumed, power-to-heat dominates district heating from 2030 on and substitutes for nearly all other alternatives in 2050. In both scenarios, power-to-heat takes over 100% of the individual heating supply from 2040 on. This happens even though potential CO_2 emissions caused by the individual heating sector are not constrained by the overall CO_2 emissions budget, unlike combined heat and power or fuel-to-heat technologies in the district heating sector. This results in a significant increase of electric energy demand of more than 200 TWh_{el} in 2030 and finally around 110 TWh_{el} in 2050, all in addition to the conventional electric energy demand in the Decreasing Heat Demand scenario. In the Constant Heat Demand scenario, this amounts to even stable 260 TWh_{el} from 2040 on, indicating a conservative upper bound in terms of heat energy demand development. In terms of power-to-heat investments, the two heat energy demand scenarios show a clear difference in individual heating. The reduced individual heat demand can be covered by a mix of air source heat pumps and some electric boiler capacity. If individual heat demand does not experience such reductions, the future capacities are dominated by ground source heat pumps and electric boilers. A minor fraction of air source heat pumps appears later in time.

An increased electric energy demand of such magnitude affects the development of electricity supply capacities significantly. In particular, wind power along with capacity of combined-cycle and open-cycle gas turbines expand significantly. Unlike for wind power, the increased use of power-to-heat does not show any impacts on the expansion path for photovoltaic, since its capacity factors behave anti-cyclical to space heating demand variations. Furthermore, among the newly installed capacities fueled by gas are power-only generation technologies that clearly dominate, whereas there are no significant investments into combined heat and power plants. Consequently, the combination of highly efficient combined-cycle gas turbine plants with heat pumps in times of low renewable power availability appears to be more efficient and flexible than bivalent combined heat and power plants.

Only in the hypothetical scenarios without power-to-heat is there a short revival of coal-fueled combined heat and power for district heating. However, its use is nearly phased-out in 2050. Instead gas-fueled heat-only plants dominate the supply in 2050 as the least CO_2 intensive technology for district heating. Consequently, the results indicate no future for combined heat and power technology.

The individual heating supply becomes more diverse with a small share of biomass

furnaces if the use of power-to-heat technology is suppressed. The bulk of supply comes from modern condensation boilers fueled by gas and oil.

Moreover, there are significant impacts of substantial power-to-heat usage on the requirement for storage facilities. Most important variations come from batteries and power-to-gas. Batteries expand a lot less in combination with power-to-heat compared to results in a power system-only analysis. In contrast, the need for power-to-gas capacity is very much elevated. Where the former effect is evenly strong in the decreasing and constant heat energy demand developments, the latter effect is stronger in the pessimistic scenario. Consequently, when power-to-heat as a flexibility alternative is taken into account, power-to-gas with zero-cost for storage volume is favored in the long run over comparatively highly cycle-efficient but costly batteries, since frequent storage activities are reduced. Suppressing investments into power-to-heat or not, does not reveal any substantial expansions of heat storage, neither in individual nor in district heating supply; as could be expected given its significant lower costs in comparison to power storage. Only in the Constant Heat Demand scenario is district heating storage volume doubled in 2050. Hence, the expected greater role of heat storage opposed to power storage requires further verification.

Acknowledgment

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5 Urban energy transition: The impact of increasing renewable energy sources on the Berlin power and heat energy systems

Urban energy transition: The impact of increasing renewable energy sources on the Berlin power and heat energy systems

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Highlights

- Development of a joint techno-economic power and district heating optimization model with endogenously determined temperature levels.
- Using Berlin as a case-study to analyze optimal technology investments and operation under increasing system penetration by electric renewable energy and the assumed transformation of the district heating network toward lower maximum supply temperature.
- The study was carried out taking into consideration the envisaged Berlin Energy and Climate Protection Program, which focuses on combined heat and power, power-to-heat, heat pumps, and storage for power and heat.
- Findings: continued use of district heating with alternative technologies in the future, such as large-scale ground source heat pumps, electric boilers and biomass-fueled heat-only plants. There is no future for combined heat and power.

Abstract

In addition to adhering to national and European policies, the Berlin state government pursues its own energy and climate protection program. In this study, a joint techno-economic power and district heating optimization model was developed to analyze the city's optimal technology mix under increasing renewable energy penetration and the assumed transformation of the district heating network toward lower maximum supply temperatures. Results show a different picture for the future Berlin energy system than envisaged by the state's energy and climate protection program: continued operation of the district heating network supplied by power-to-heat accompanied by biomass-fueled heat-only plants. There is no future for combined heat and power.
Keywords: district heating, combined heat and power, sector coupling, power-to-heat
JEL codes: C61, D61, Q42

5.1 Introduction

The large-scale deployment of vRES, such as wind power and photovoltaics (PV), for electricity is an objective pursued by many countries, including Germany, as part of their overall energy policies, aimed at reducing their CO_2 emissions. The fluctuations in the power generation of vRES require additional flexibility measures in order to economically deal with temporary shortages and surpluses of power supply. Until 2050, 80% of the German yearly electricity demand is supposed to be covered by RES (BMWi, 2018b). Sector-coupling in the form of power-to-heat is considered to be a suitable alternative to power storage. In particular, urban areas like Berlin that have a large and well-integrated district heating network, can offer important potentials to national power systems to integrate power surpluses from vRES (Bloess, Schill, and Zerrahn, 2018; Henrik Lund, Werner, et al., 2014). In return, such cities can benefit from integrating these surpluses when they themselves aim to decarbonize their energy system. The Berlin district heating network is among the very largest in the world and, after Moscow and Warsaw, the third largest in Europe. It supplies around 1.2 million dwellings and consists of around 1,850 km of piping, growing yearly by around 25 km. This study seeks to evaluate the role of CHP, power-to-heat, and the district heating network in the city-state of Berlin in the context of an increasing penetration of electric RES on the national level and future energy and climate protection policies on the city-state level.

5.1.1 Research objective

This work investigates the Berlin energy sector, consisting of the city's power and district heating systems, in the context of the increasing RES penetration in the national electricity system in Germany. In doing so, a special focus is put on the technical transformation of the Berlin district heating network toward lower supply and return temperatures. Various simulations for a stepwise increase in the RES penetration of the national electricity system and a stepwise lowering of the district heating network's supply and return temperatures were run while taking into consideration the political constraints of the Berlin Energy and Climate Protection Program (BECP) and additionally taking a business-as-usual (BAU) view without these political constraints into account. In particular is analyzed the economical optimal mix of technologies as considered by the BECP, these being various CHP plant types and conventional power generation technologies, PV, wind power, gas and biomass-fueled heat-only plants, electric boilers and large-scale ground source heat pumps (GSHPs) for power-to-heat, solar-thermal collectors, as well as battery storage, power-to-gas, and thermal storage by means of thermal energy storage (TES) tanks and heat accumulation in the district heating network piping. To the best knowledge of the author there are as yet officially no definite plans to transform the Berlin district heating network into a low temperature network. It is nevertheless useful to examine which techno-economic options would arise if such a transformation were to hypothetically take place.

This analysis is based on a techno-economic optimization model minimizing annual costs for investment and operation that covers the power system in Germany and the joint power and district heating system in Berlin. The demand and supply of power and heat are

balanced hourly over a year. The model is implemented as a MILP in GAMS and solved with the Gurobi solver (GAMS, 2018; Gurobi, 2018). While the power system is represented in a single node that is abstracted from the power grid, the district heating infrastructure is represented here as a stylized congestion-free 10-node heat transmission model that spatially aggregates district heating demand and supply. A special focus is put on the temperature level in the district heating network for each hour. This enables, firstly, the introduction of additional technical constraints to analyze the operation of GSHPs, solar-thermal collectors, and heat storage in a more realistic way than when those constraints are neglected (which leads to overestimations) and, secondly, an analysis of the effects of the utilization of these alternative heat technologies when lowering the temperature level in the district heating network.

5.1.2 Literature review

Energy flows in a district heating network are determined by the mass flow rate of the energy carrier water and its temperature level. In order to model these flows, X. Liu et al. (2016) separate the problem into a hydraulic and a thermal model. Whereas the hydraulic model determines the mass flow rate, the thermal model determines the temperature level. To avoid non-linearities, X. Liu et al. (ibid.) compare an integrated and a decomposed approach to solving the problem iteratively. Their analysis reveals fewer iterations in the integrated approach. In contrast, this analysis intends to also include inter-temporal relations, such as those caused by storage. Also, since the real network topology of the Berlin district heating system is unknown to the author, a stylized heat transmission model similar to the work by Christidis et al. (2012) is assumed; this model does not consider any slopes in the piping that would affect hydraulics. Therefore, this work does not consider the hydraulic problem and instead determines mass flow rates and pumping work by means of exogenous calibration. Figure 5.5 illustrates the stylized heat transmission model employed here and is described in more detail in Section 5.3. This is partly inspired by the work of Østergaard and Andersen (2016), who emphasized endogenously determined transmission losses in district heating. They also applied a simplified network model with varying supply and return temperatures influencing heat losses. This feature was important for their analysis as they juxtaposed the use of large-scale heat pumps in a low temperature network with the additional deployment of so-called booster heat pumps located close to the point of consumption. Also, in this work, heat transmission losses are determined endogenously in order to analyze them being subject to the network's temperature level, and to analyze their impact on using power-to-heat centrally and before heat transmission rather than directly at the point of consumption. This work is also influenced by Salpakari, Mikkola, and P. D. Lund (2016), who analyze the flexibility potential provided by district heating in Helsinki for integrating RES (ibid.). Special features of their methodology, such as technical constraints in operation of heat pumps and TES tanks imposed by temperature limits, are also considered here, in particular their role within the future Berlin energy system. Salpakari, Mikkola, and P. D. Lund (ibid.) also modeled the heat storage mechanism by the capability of the district heating network to accumulate heat energy in the piping. Building

on this, this work implements the degree-of-freedom to raise the supply temperature above levels required by the current heat load in order to make use of this heat accumulation hours later and to economically optimize the energy system's operation. Modeling this feature enables the analysis to account for the actual flexibility provided by an existing district heating infrastructure.

The novelty of this work consists of:

(1) analyzing the joint power and district heating supply of Berlin as a case study;

(2) developing a stylized heat transmission model for sector-coupling effects in which the temperature level and heat transmission losses are determined endogenously;

(3) accounting for the flexibility provision of district heating piping by means of heat accumulation;

(4) considering additional technical constraints due to temperature limits for alternative heating technologies, such as large-scale heat pumps, solar-thermal collectors, and heat storage; and

(5) analyzing the effects of lowering the district heating network's temperature level on the utilization of these alternative heating technologies.

The sector-coupling joint power and district heating model developed for this study is used in a scenario analysis to show the economically optimal technology and operation mix for Berlin under increasing RES penetration in the national electricity system and a supplementary energy and climate protection policy for the city. Special focus is placed on the future role of CHP, power-to-heat, and the city's district heating network. On the one hand, this work addresses energy system modelers in terms of the proposed methodology and its features, and on the other hand it also addresses policy makers, since the outcomes of the analysis have important implications for the city's energy and climate protection policy.

The remainder of the paper is structured as follows: Section 5.2 introduces the Berlin Energy and Climate Protection Program (BECP), including some caveats as well as the current status of the Berlin energy sector and its perspectives. Section 5.3 illustrates in detail the methodology applied in this analysis, and Section 5.4 shows the data used and its sources and outlines some additional assumptions. Section 5.4 also illustrates the scenarios under investigation. Section 5.5 presents the results and Section 5.6 summarizes the most important conclusions of this analysis.

5.2 The Berlin energy system – status quo and energy and climate protection policy

5.2.1 Berlin's energy and climate protection policy

In 2016 the Berlin state parliament passed the Energy Transition Act, an act designed to enforce supplementary contributions by the city state to the German *energiewende*, the national energy transition policy aimed at climate protection (Berlin, 2017). The basic

objective of the act is to achieve a significant reduction of CO_2 emissions. For this the act requires that the Berlin state government implements strategies and actions to reduce the city's CO_2 emissions by at least 40% by 2020, 60% by 2030, and 85% by 2050 compared to the 1990 levels. To achieve these targets, the act demands the regular elaboration of the BECP, which contains strategies and measures to reduce energy consumption, increase energy efficiency, and increase the share of RES. Future electricity and heat energy infrastructures should also be secure, economical, climate protective, and increasingly based on RES. Furthermore, the act imposes the phasing-out of local energy supplies based on lignite by 2017 and those based on hard coal by the end of 2030.

Berlin's energy and climate protection policy shows clear parallels to national policies and was developed over several years. In 2014 the Berlin state government released the final results of a feasibility study for a climate-neutral city by 2050 (SenSU, 2014) and in 2015 a special commission of the House of Representatives of Berlin released its final report on Berlin's future energy supply (AGH Berlin, 2015). Finally, in 2018, the state parliament approved the BECP (SenSU, 2015, 2018), which specifies the state government's strategies and measures in more detail. Since 2019 these are accompanied by a feasibility study concerning the phase-out from coal in district heating by the end of 2030 (BET, 2019). The BECP defines five fields of action: the energy sector, buildings, economic activity, mobility, and household consumption. The energy sector consists of Berlin's power and district heating supplies. Since nearly all power and district heating is generated in local CHP plants, these two supplies are highly interlinked. For each field, the BECP identifies emission reduction potentials and a different set of strategies and measures to achieve these. Figure 5.1 illustrates the planned CO_2 emission reduction path for Berlin. CO_2 emission levels in all five fields of action are indicated in blue. From this graph it can be seen that total CO_2 emissions amounted to 29.2 Mt in 1990 and dropped to 19.5 Mt in 2015. The BECP aims to further reduce the emissions to 4.3 Mt by 2050. CO_2 emission levels of Berlin's power and district heating sector, which provides energy consumed in the other four fields of action, is indicated in black. According to state statistics, the energy sector emitted about 14.1 Mt CO_2 in 1990 and halved these to 7.1 Mt in 2015 (AfS BB, 2018b). The BECP budgets for a decrease in this field of action down to 3.9 Mt by 2050.

Carbon emissions do not affect the local CO_2 concentration at its origin in the long term, and atmospheric mechanisms that determine the planet's climate are global ones; consequently, the origin of emissions is irrelevant for global climate protection. Therefore, the emission trading system (ETS) implemented by the European Union (EU) is a Europe-wide instrument for reducing greenhouse gas emissions in the economically most effective and efficient way; the EU aims to expand it to a global trading system. Nevertheless, the Berlin state government considers it reasonable to develop a local CO_2 emission balancing system for the city within the BECP based on the notion that reducing this balancing system's emissions would lead to lower global emissions, and thus, to climate protection. Furthermore, a local energy balance system is developed for the city in the BECP. In order to decarbonize the city's energy supply, the program aims to substantially reduce final energy consumption between now and 2050 and demands that the use of RES originates from within the city state. In this regard Berlin is being treated as an isolated island system

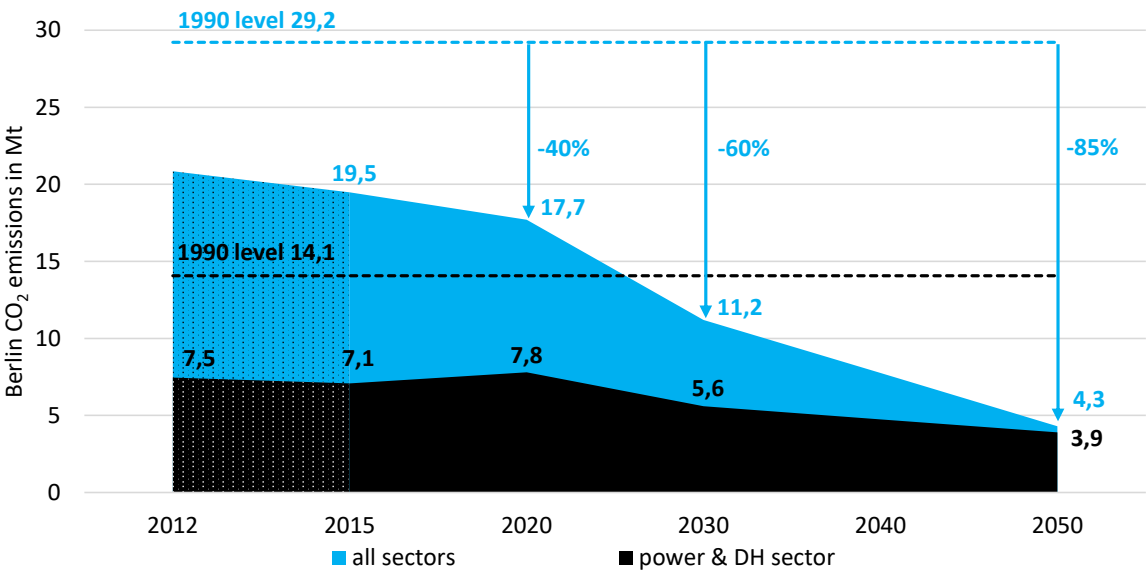


Figure 5.1: Past developments and targets of Berlin CO_2 emissions.

Note: Total Berlin emissions are calculated according to polluter principal balance, Berlin energy sector emissions according to source balance.

Source: Own depiction based on SenSU (2015) and AfS BB (2018b).

with absolute targets concerning final energy consumption and CO_2 emissions by 2050. However, this approach could potentially lead to inconsistencies in those cases in which there are developments beyond the state government's control. For instance, if the Berlin population grows (either through higher birth rates or through immigration), this could lead to higher levels of energy consumption and the city missing its politically set targets. Still, there is no reasonable explanation for a policy controlling the energy consumption to be more or less in a particular place such as Berlin compared to any other place in the world. The same holds for CO_2 emissions that could be connected to this additional energy consumption. For global climate protection it is irrelevant whether emissions are caused within or outside Berlin. A significant population growth in Berlin by 2050 is a likely scenario and is even anticipated by the state government (SenSW, 2017). Controlling Berlin's population increase by means of active migration or population policy just in order to fulfill local energy consumption and emissions targets would be a controversial endeavor to say the least.

Moreover, unlike heat energy supplies that require local energy systems, Berlin's electric energy supply is embedded into the European electricity market and a continental power transmission infrastructure. Figure 5.3 in Section 5.2.2 shows that nearly half of Berlin's electricity is imported from this European market. On top of the European ETS, the German Federal Government has additionally imposed various energy and climate protection policies aimd toward the decarbonization of the national energy supply. Among other

goals, the federal policy formulates targets for the share of RES in the national electricity mix of at least 35% in 2020, 50% in 2030, 65% in 2040 and 80% in 2050 (BMWi, 2018b). These targets are intended to be achieved mainly through the expansion of onshore and offshore wind and PV power. Therefore, concerning electric energy, it is questionable why Berlin should necessarily be in charge of its own electricity production, as required by the BECP, when it does not possess any special locational advantage for these technologies. In an EU built on the notion of free trade, energy self-sufficiency cannot be a reasonable justification. Additionally, Berlin is located in the geographic center of the 50Hertz control area, and is its biggest power consumer. Compared to other German and European transmission control areas, the 50Hertz zone is already characterized as a net exporter of electricity due to its low consumption and substantial power generation from wind and PV. Consequently, there is no reason why the use of RES must necessarily originate from Berlin rather than from a different region, in which power generation might be more economical.

Furthermore, in its vision of transforming Berlin's energy supply, the BECP takes a long-term view until 2050. It is impossible for anybody to know today what the most effective and efficient means and technologies of achieving reductions in energy consumption and CO_2 emissions will be over the course of such a long time span. Nevertheless, the BECP formulates no technology-independent, open strategies that aim to mitigate CO_2 emissions in the most cost-effective way or to provide incentives to energy consumers. On the contrary, the measures for the energy sectors listed by the BECP promote very specific technologies, for example CHP, wind, and PV power.

5.2.2 The Berlin energy sector – status quo and perspectives

The BECP must be seen in context of the current and future development of the city. After a long period of stagnation, Berlin's economic activity became dynamic around 2005 and since then the GDP growth rate has been substantially above the national level. The city's population also started rising in 2014, and numbered more than 3.6 million habitants in 2017. Estimates by the state government anticipate a continuous increase to a population up to nearly 4 million habitants by 2030 (SenSW, 2017). Figure 5.2 illustrates this and some other indicators.

Figure 5.3 depicts the composition of Berlin's total final energy consumption in 2015. Major forms of energy used are electricity, district heating, and fuels for individual heating and non-electric mobility (AfS BB, 2018b). The Berlin energy sector as identified as field of action by the BECP includes only power and district heating supplies, while individual heating is subsumed under the field of buildings and mobility is a field of action of its own. The energy sector accounts for 37% of Berlin's total final energy consumption , with a share of 21% for electricity and 16% for district heating. Furthermore, 49% of Berlin's electricity supply is based on power imports. 68% of all electricity production and 60% of district heating energy is generated by CHP.

More details about the current status quo are given in Figure 5.4; this includes capacities and primary energy consumption for the annual output of the Berlin power sector, Figure 5.4a, and the same of district heating, Figure 5.4b. Apart from one conventional open-cycle

gas turbine and the few wind turbines and PV power generators, all power plants in Berlin are CHP plants. Up to a fifth of the thermal CHP capacity for district heating is backed by gas-fueled central heat-only plants. Major sources of primary energy are lignite, hard coal, and gas. There are also two smaller CHP plants fueled by biomass, but these play a minor role.

The major starting point for pulling Berlin CO_2 emissions down to the levels shown in Figure 5.1 is the energy sector, since this provides an important share of the final energy supply for all other fields of action and comprises a comparatively small number of actors in control over a substantial source of local CO_2 emissions. Here the BECP follows the strategy of a fuel switch away from lignite, coal, and oil toward the use of gas. In particular, due to the high total fuel efficiency of CHP, the BECP highlights its role in modern and flexible gas-fueled combined-cycle gas turbines. The only Berlin CHP plant fueled by lignite, HKW Klingenberg, was already decommissioned in 2017. Furthermore, at the plant site Lichterfelde, one of the three old gas-fueled blocks was replaced by a modern combined-cycle gas turbine with extraction-condensation steam turbine in 2018. All coal-fueled energy production in other CHP plants is supposed to be phased-out by the end of 2030 at the latest. This will affect the four current CHP plants: HKW Moabit A, HKW Reuter C, and HKW Reuter West D and E. Moreover, amongst other measures, the BECP intends to integrate more RES, such as wind and PV power as well as biomass, geothermal, and solar-thermal energy. These technologies are supposed to be accompanied by adequate auxiliary technologies — such as batteries for power storage, heat storage, power-to-heat, and power-to-gas — for enhanced flexibility.

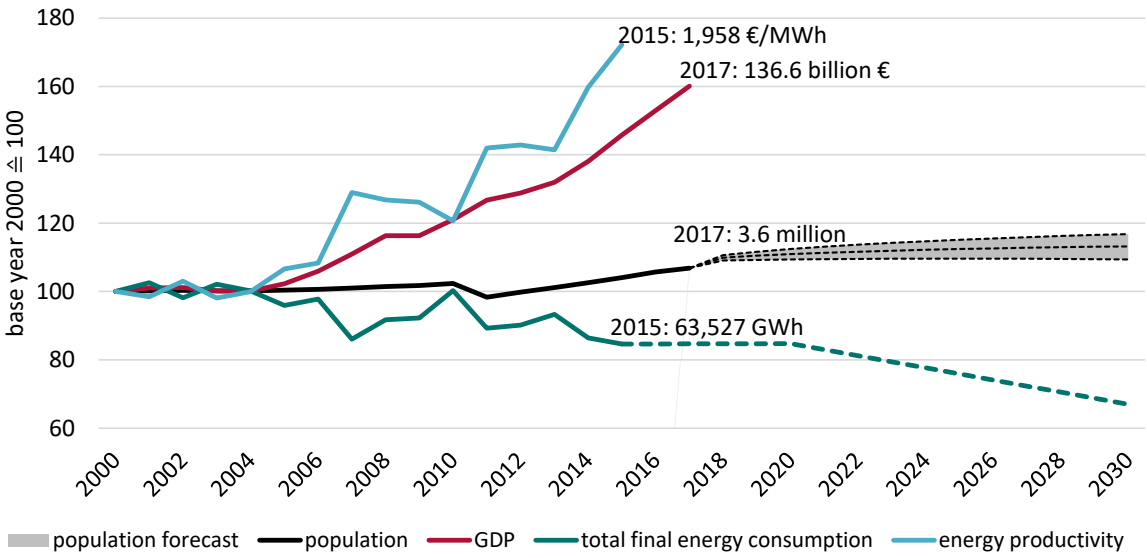


Figure 5.2: Development of Berlin's population, GDP, total final energy consumption, and energy productivity.

Source: Own depiction based on AfS BB (2018a) and SenSW (2017).

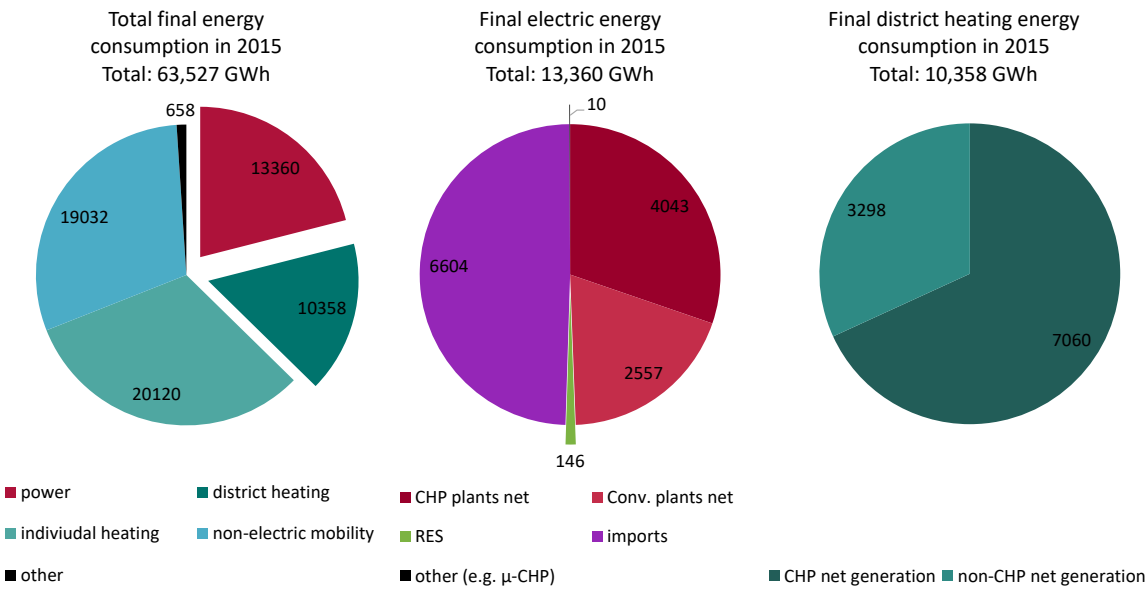


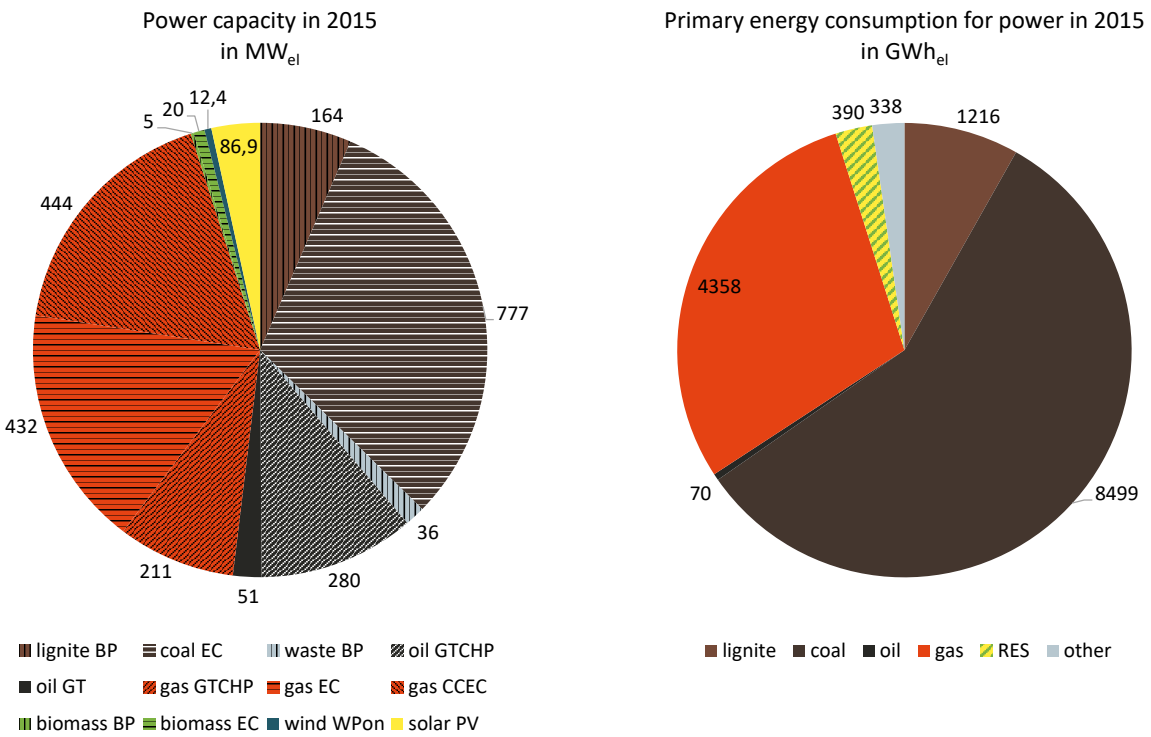
Figure 5.3: Berlin's final energy composition and primary sources of electricity and district heating consumption in 2015.

Source: Own depiction based on AfS BB (2018b).

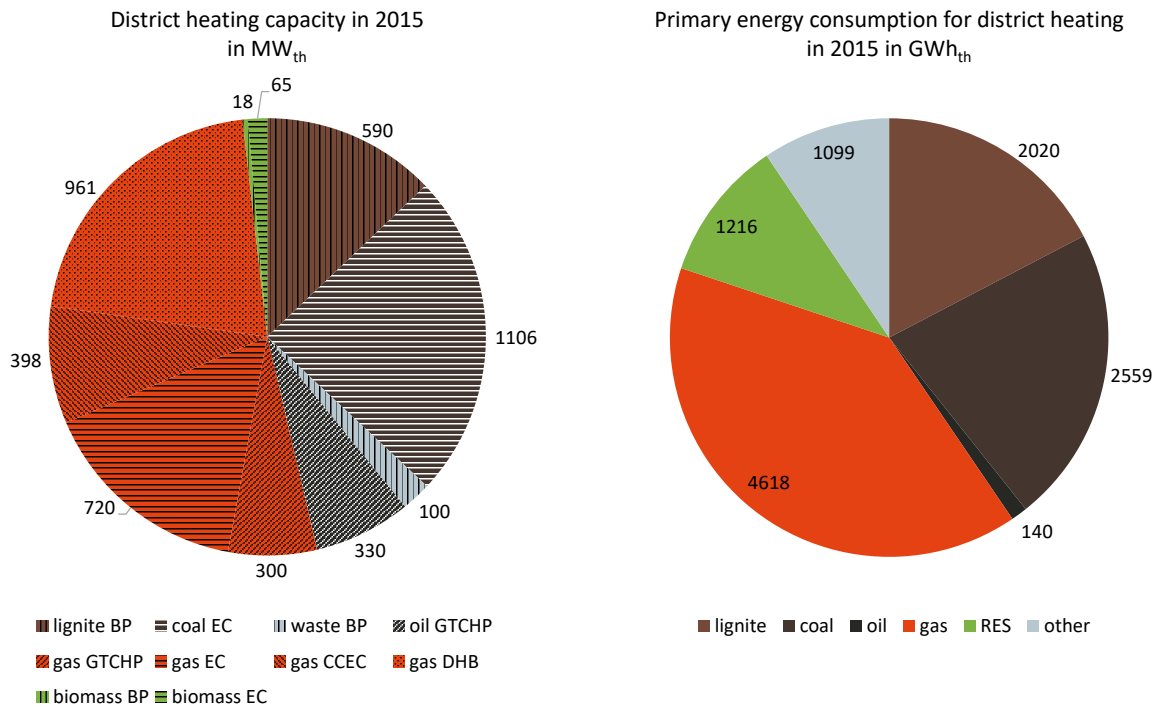
Moreover, the BECP intends to maintain the existing district heating network, to expand it further, and to continuously increase its supply density. Heat energy for space and domestic hot water heating is transported in the form of pressurized hot water to reach supply temperatures of up to 140°C. However, unconventional heat technologies for district heating, such as large-scale GSHPs exploiting geo-thermal energy or solar-thermal heat collectors, require low network temperatures to be able to inject heat energy. Therefore, the BECP also mentions the technical transformation of the Berlin district heating network toward lower supply and return temperatures. Several measures formulated in the BECP, such as more energy efficient buildings, the lowering of supply and return temperatures, tapping low temperature heat sources and RES, and the smart integration with other infrastructures, lead to what Henrik Lund, Werner, et al. (2014) define as 4th generation district heating. As Nielsen et al. (2016) illustrate, such a district heating network can also consist of a hierarchy in which a high temperature transmission network supplies various local distribution networks with a lower temperature level, thereby enabling the integration of alternative low temperature heat sources in these sub-networks (ibid.).

5.3 Methodology

The model presented in this work is depicted in Figure 5.5. It combines a techno-economic investment and dispatch model for Berlin's electric energy supply with a stylized heat transmission network representing the Berlin district heating network. This heat trans-



(a) Berlin's power capacities and primary energy consumption in 2015.



(b) Berlin's district heating capacities and primary energy consumption in 2015.

Figure 5.4: Capacities and primary energy consumption of Berlin's power and district heating systems in 2015.

Source: Own depiction based on AfS BB (2018b).

mission network allows for modeling the course of heat energy flows with endogenously determined cascading temperature levels from a central heat supply station to the point of district heating consumption and back to the central heat supply station. This feature helps, firstly, to estimate heat transmission losses of supply and return heat energy flows depending on ambient and network temperature; secondly, to capture heat storage effects by accumulating heat within the network piping; and, thirdly, to impose realistic thermal limits for the operation of extra thermal energy storage (TES) tanks, ground source heat pumps (GSHPs), and solar-thermal heating. A major obstacle to the integration of large-scale GSHPs and solar-thermal heating in the current Berlin district heating network is its high temperature level. In times of peak heat load, the Berlin district heating network operates at a maximum supply temperature between 130℃ and 140℃. If the temperature level at the point of heat injection is too high, these technologies become too inefficient and their operation thus too costly — or the heat injection even becomes technically impossible. Moreover, the operation of heat storage, either by means of central large TES tanks or by means of heat accumulation within the piping, also crucially depends on the current operational temperature levels. It is therefore important to analyze endogenously-determined capacity investments and the operation of these technologies concurrently to endogenous short-term temperature settings within the district heating network. Furthermore, this model allows for exogenously lowering the maximum supply temperature of the heat transmission network as if such a technical refitting has taken place, in order to analyze how investment and operational decisions evolve depending on the maximum temperature levels.

In the following sections, a detailed formulation of the model is given. For a better overview, this formulation is divided into three parts. The first part shows equations and constraints relevant for both the power and district heating system. The second and third parts highlight only those equations and constraints relevant for the power and district heating systems, respectively. Figure 5.5 shows information that aids understanding especially those formulations relevant for the district heating system, but gives also an overview of interactions with the power system.

5.3.1 The joint power and district heating system

The future development of Berlin's power generation capacities will crucially depend on the evolution of power generation in Germany and on national energy and climate protection policies. Therefore, before calculating Berlin's joint power and district heating model separately, the national power system is solved in a linear dispatch and investment model in order to obtain hourly prices and CO_2 emission intensities of each megawatt under the constraint of minimum RES system penetrations, the nuclear phase-out, and the coal exit as required by the national energy and climate protection policy. The hourly shadow prices and CO_2 emission intensities are then passed on to the Berlin joint power and district heating model, in which Berlin is assumed to be a price taker.

For readability, all variables are in capital letters, while parameters are in lower case letters. For brevity, existing and potentially new capacities are not distinguished in this

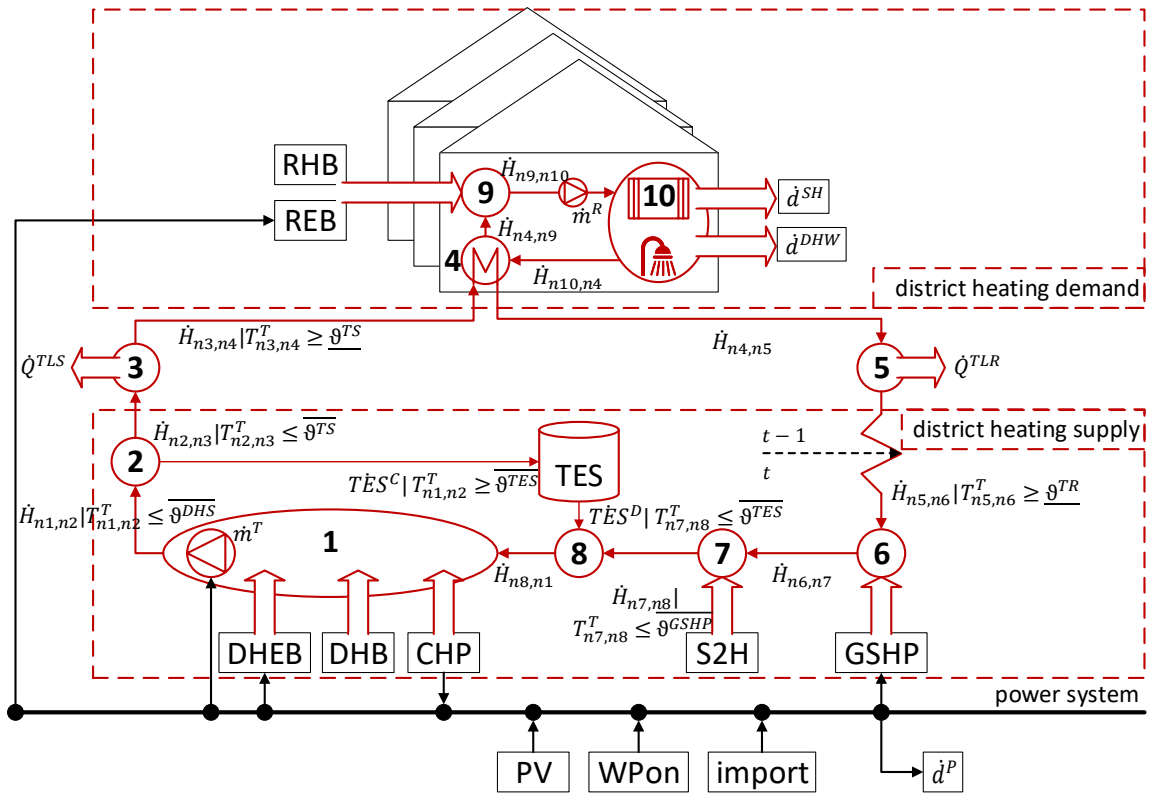


Figure 5.5: Berlin power and district heating model.

notation. A nomenclature at the very end of the article lists all abbreviations, indices, parameters, and variables. Public access to the full model formulation and its data is available (Bloess, 2019b).

Objective function

The model minimizes total costs, TC, in the objective function (5.1). Total costs are composed of costs for operation, OC, fixed operation and maintenance, $FO\&MC$, investments, IC, and imports, IMC. These cost terms are highlighted in more detail in equations (5.2) to (5.4).

$$TC = OC + FO\&MC + IC + IMC \tag{5.1}$$

Operating costs in equation (5.2) are composed of costs for fuel and ramping. The fuel consumption, $FC_{p,i,f,t}$, of each plant block p with technology i fired with fuel f in each time step t must be distinguished for various technologies according to equations (5.3). Fuel consumption in conventional power plants depends only on the power output ($G_{p,i,f,t}$), (5.3a). For CHP plants it depends on their power and heat ($Q_{p,i,f,t}$) output according to whether their technology type is a back-pressure steam turbine (BP), (5.3b), extraction-condensation steam turbine (EC), or gas turbine CHP (GTCHP) plant with heat recovery

boiler, (5.3c). Fuel consumption of heat-only plants is calculated according to the equation (5.3d). As an alternative to conventional gas fuel, all technologies fired by gas can consume synthetic gas, $SG^{D}_{p,i,f,t}$, produced by means of power-to-gas. Ramping costs result from short-term load changes up, $G^{up}_{p,i,f,t}$, and down, $G^{dn}_{p,i,f,t}$.

$$OC = \sum_{p}\sum_{i}\sum_{f}\sum_{t}\left(c^{var}_{p,i,f}\cdot FC_{p,i,f,t} + c^{ramp}_{p,i,f}\cdot\left(G^{up}_{p,i,f,t} + G^{dn}_{p,i,f,t}\right)\right) \tag{5.2}$$

$$FC_{p,i,f,t} + SG^{D}_{p,i,f|f\hat{=}gas,t} = \frac{G_{p,i,f,t}}{\eta_{p,i,f}} \qquad \forall\ p, i_{cp}, f, t \tag{5.3a}$$

$$FC_{p,i,f,t} + SG^{D}_{p,i,f|f\hat{=}gas,t} = \frac{G_{p,i,f,t} + Q_{p,i,f,t}}{\eta_{p,i,f}} \qquad \forall\ p, i_{chp_{bp}}, f, t \tag{5.3b}$$

$$FC_{p,i,f,t} + SG^{D}_{p,i,f|f\hat{=}gas,t} = \frac{G_{p,i,f,t} + \beta_{p,i,f}\cdot Q_{p,i,f,t}}{\eta^{cm}_{p,i,f}} \qquad \forall\ p, i_{chp_{ec}}, f, t \tag{5.3c}$$

$$FC_{p,i,f,t} + SG^{D}_{p,i,f|f\hat{=}gas,t} = \frac{Q_{p,i,f,t}}{\eta_{p,i,f}} \qquad \forall\ p, i_{hp}, f, t \tag{5.3d}$$

Total import costs occur through imports from the rest of Germany to Berlin when solving the Berlin joint power and district heating model separately and are the sum of all hourly products of imported power, IMP_t, and its import price per $\mathrm{MW_{el}}$, p^{m}_{t}. For the composition of fixed O&M and investment costs refer to the Appendix D.2.

$$IMC = \sum_{t}\left(p^{m}_{t}\cdot IMP_t\right) \tag{5.4}$$

5.3.2 Power system formulation

Power balance

On the demand side, the power balance equation for Germany (5.5) consists of the conventional power demand, d^{P-B}_{t}, power demand due to power-to-gas, D^{P2G-B}_{t}, and the charging of power storage, ${PS^{C}_{p,i,f,t}}^{-B}$. An additional power demand in the Berlin power balance (5.6) can occur due to power-to-heat, D^{P2H}_{t}, and for the pumping work, D^{PW}_{t}, that keeps the district heating network running. Pumping work demand occurs only when the model determines that the heat transmission network is operating in a particular hour, by means of the binary variable X^{T}_{t} in equation (5.7). The model requires the demand side to be covered each hour either by power generation, $G_{p,i,f,t}$ or power storage discharging, $PS^{D}_{p,i,f,t}$. Berlin power imports, IMP_t, connect the supply side of the Berlin power balance with the demand side of the remaining German system. Equation (5.8) aggregates the hourly power-to-heat demand of various power-to-heat technologies.

$$d^{P-B}_{t} + D^{P2G-B}_{t} + {PS^{C}_{p,i,f,t}}^{-B} + IMP_t = \sum_{p}\sum_{i}\sum_{f}\left({G_{p,i,f,t}}^{-B} + \eta_{p,i,f}\cdot {PS^{D}_{p,i,f,t}}^{-B}\right)\ \forall\ t \tag{5.5}$$

$$d_t^{P^B} + D_t^{P2H} + D_t^{P2G^B} + PS_{p,i,f,t}^{C^B} + D_t^{PW} = \sum_p \sum_i \sum_f \left(G_{p,i,f,t}{}^B + \eta_{p,i,f} \cdot PS_{p,i,f,t}^{C^B} \right) + IMP_t \; \forall \, t \tag{5.6}$$

$$D_t^{PW} = X_t^T \cdot d_t^{PW} \qquad \forall \, t \tag{5.7}$$

$$D_t^{P2H} = \sum_p \sum_{i_{p2h}} \sum_f G_{p,i,f,t} \qquad \forall \, t \tag{5.8}$$

General power plant constraints

According to constraint (5.9), power generation per plant is always limited by available plant capacity. Berlin power generation capacity is either maintained or decommissioned by the binary decision variable $X_{p,i,f}^D$ in constraint (5.10). Power generation by vRES depends not only on installed capacity but also on availability due to weather conditions, $cf_{i,f,t}^{vRES}$, and is also subject to potential curtailment, $C_{p,i,f,t}^{vRES}$, by constraint (5.11).

$$G_{p,i,f,t} \leq \overline{G}_{p,i,f} \qquad \forall \, p, i, f, t \tag{5.9}$$

$$\overline{G}_{p,i,f} = \left(1 - X_{p,i,f}^D\right) \cdot \overline{g}_{p,i,f} \qquad \forall \, p_B, i, f \tag{5.10}$$

$$G_{p,i,f,t} + C_{p,i,f,t}^{vRES} = cf_{i,f,t}^{vRES} \cdot \overline{G}_{p,i,f} \qquad \forall \, p, i_{vres}, f, t \tag{5.11}$$

CHP constraints

Additional constraints exist for the relationship of power and heat output in CHP plants. In BP plants, power and heat output is strictly fixed by the power-over-heat-ratio, $\sigma_{p,i,f}$, in equation (5.12a). EC and GTCHP plants are modeled by a lower bound (5.12b) and an upper bound constraint (5.12c). The power-loss-coefficient $\beta_{p,i,f}$ is computed for extraction-condensation CHP plants according to $\beta = \frac{\eta^{cm}}{\eta} \cdot (1 - \sigma) - \sigma$ and is defined as zero for gas turbines with heat recovery boilers. For deeper insights into CHP modeling refer to Bloess (2020).

$$G_{p,i,f,t} = \sigma_{p,i,f} \cdot Q_{p,i,f,t} \qquad \forall \, p, i_{chp_{bp}}, f, t \tag{5.12a}$$

$$G_{p,i,f,t} \geq \sigma_{p,i,f} \cdot Q_{p,i,f,t} \qquad \forall \, p, i_{chp_{ec}}, f, t \tag{5.12b}$$

$$G_{p,i,f,t} \leq \overline{G}_{p,i,f} - \beta_{p,i,f} \cdot Q_{p,i,f,t} \qquad \forall \, p, i_{chp_{ec}}, f, t \tag{5.12c}$$

Additional power system constraints

For the future scenario computations in 2020, 2030, and 2050, some additional constraints are imposed on the model to account for policy-related developments in the national power system. For example, plants that have exceeded their technical lifespan in those years will be exogenously decommissioned. Moreover, the agenda of the Atomic Energy Act (AEA), which compels Germany to phase out its nuclear energy, requires exogenous decommissioning of nuclear plants and, further, the national coal exit policy requires all coal plants

to have ceased operation by 2050. When computing the German investment and dispatch power system model, constraint (5.13) is additionally introduced in order to account for the imposition of minimum shares of RES generation according to governmental targets (BMWi, 2018b). Furthermore, constraint (5.14) represents limitations on the use of biomass as an energy carrier, since access to it is bounded.

$$\sum_{p}\sum_{i_{cp}}\sum_{f}\sum_{t} G_{p,i,f,t} \leq \left(1 - s^{RES}\right) \cdot \sum_{t}\left(d_t^P + D_t^{P2G} + \sum_{p}\sum_{i}\sum_{f}\left(PS^C_{p,i,f,t} - \eta_{p,i,f} \cdot PS^D_{p,i,f,t}\right)\right) \tag{5.13}$$

$$\sum_{p}\sum_{i}\sum_{f}\sum_{t} FC_{p,i,f,t} \leq \overline{f^{bio}} \tag{5.14}$$

Figure 5.6 indicates the price duration curves obtained from the German power balance that become steeper at higher RES penetration levels.

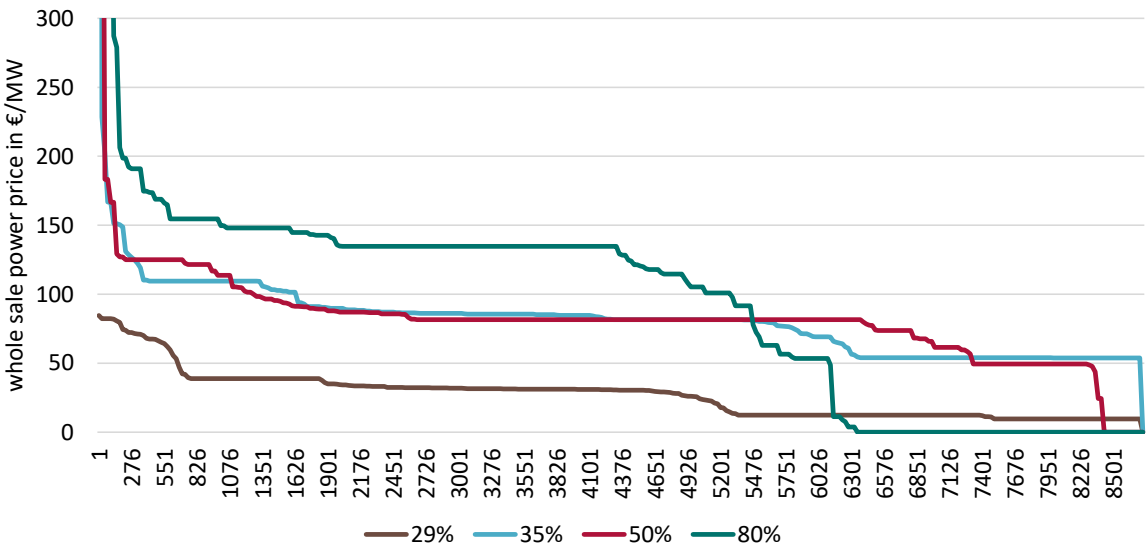


Figure 5.6: Ordered marginal power prices for various RES penetrations.

5.3.3 District heating system formulation

Analogously to power generation, heat generation is limited by installed capacity according to constraint (5.15).

$$Q_{p,i,f,t} \leq \overline{Q}_{p,i,f} \;\forall\; p, i, f, t \tag{5.15}$$

District heating balance

The district heating balance (5.16) equalizes all inflowing, $H_{nn,n,t}$, and outflowing, $H_{n,nn,t}$, heat energy streams for each hour and node. Figure 5.5 numerates all of the nodes of

the stylized heat transmission network and shows their connections to each other. Each node represents a different function within the temperature cascading system in the network. Node ① represents the district heating supply site, in which all heat injections of the district heating technologies that are technically unlimited in lifting the district heating transmission temperature level up to the maximum supply temperature take place. These technologies are CHP plants and large heat-only plants, like boilers fueled by gas, biomass (district heating boiler; DHB), or electricity (district heating electrode boiler (DHEB)). Moreover, the aggregated pumping work for keeping the heat transmission running contributes here with heat injection, since a large share of pumping work, α, dissipates in the form of heat. However, this heat dissipation is actually not lost, because it heats up the pumped water carrying the heat energy. The temperature, $T^{T}_{`n1',`n2',t}$, of the heat energy flow, $H_{`n1',`n2',t}$, leaving node ① and going to node ② is limited in the district heating supply site by $\overline{\vartheta^{DHS}} = 140$°C. Here, node ② serves as the point of heat energy withdrawal for charging TES tanks. The heat energy flow from node ② to node ④ is the supply flow and transmits heat energy generated at the district heating supply site to residential demand. All heat energy that arrives in node ④ throughout the year represents Berlin's yearly final district heating energy consumption. Node ④ is consequently the point of delivery and aggregates the entire heat exchanger capacity of all residential district heating substations in Berlin. The water flow from node ④ to node ⑥ represents the district heating return flow from the district heating customers back to the district heating supply site. Heat transmission losses, Q^{TLS}_{t} and Q^{TLR}_{t}, occur in both the supply and the return flows, leaving the cycle in nodes ③ and ⑤, respectively. The supply flow temperature, $T^{T}_{`n2',`n3',t}$, is limited by a maximum district heating supply temperature $\overline{\vartheta^{TS}}$ that is determined exogenously. Although it is of course desirable to lower the return flow temperature, $T^{T}_{`n5',`n6',t}$, as much as possible for reasons of efficiency, the model imposes here a realistic lower bound, $\underline{\vartheta^{TR}}$, since in reality the district heating network operator has no influence by means of technical

modifications.

$$
\begin{aligned}
&\sum_{nn} H_{nn,n,t}\,_{|n\neq`n6'} \\
&+\left(\sum_{p}\sum_{f}\left(\sum_{i_{chp}} Q_{p,i,f,t}+\sum_{i_{DHB}} Q_{p,i,f,t}+\sum_{i_{DHEB}} \eta_{p,i,f}\cdot G_{p,i,f,t}\right)+\alpha\cdot D_t^{PW}\right)_{|n\hat{=}`n1'} \\
&+\left(\sum_{p}\sum_{i_{gshp}}\sum_{f}(\epsilon_t\cdot G_{p,i,f,t})+\sum_{nn} H_{nn,n,t-1}-AV_t^{+}\right)_{|n\hat{=}`n6'} \\
&+\sum_{p}\sum_{i_{s2h}}\sum_{f} Q_{p,i,f,t}\,_{|n\hat{=}`n7'} \\
&+\sum_{tes}\mathrm{TES}^{D}_{tes,t}\,_{|n\hat{=}`n8'} \\
&+\sum_{p}\sum_{f}\left(\sum_{i_{rhb}} Q_{p,i,f,t}+\sum_{i_{reb}}(\eta_{p,i,f}\cdot G_{p,i,f,t})\right)_{|n\hat{=}`n9'} \\
&= \\
&\sum_{nn} H_{n,nn,t}+\sum_{tes}\mathrm{TES}^{C}_{tes,t}\,_{|n\hat{=}`n2'}+Q_t^{TLS}\,_{|n\hat{=}`n3'}+Q_t^{TLR}\,_{|n\hat{=}`n5'} \\
&+\left(d_t^{SH}+d_t^{DHW}\right)_{|n\hat{=}`n10'}
\end{aligned}
\qquad \forall\, n,t \tag{5.16}
$$

Figure 5.5 shows a break in time steps for the connection between node ⑤ and ⑥: the heat energy flow entering into node ⑥ is always one time step behind the heat energy flow leaving node ⑥. In this way the heat accumulation in the district heating piping as a heat storage mechanism can be modeled. For instance, the temperature level of the heat energy supply flow could be lifted higher than actually required by the heat demand in certain time steps. Possible reasons for this could be temporarily cheap available heat generation or the avoidance of ramping in CHP plants. This higher temperature level can be conserved in the water mass flow in the piping and allows for lower heat injection in later time steps. In this regard, the stored heat in the piping provides inherent flexibility and injections into the district heating network can be temporarily optimized in the short term to some degree. In case the district heating network is temporarily switched off (for example because there is no demand or in order to shift heat generation to residential facilities), heat flows generated before can be cast off in node ⑥ by means of the positive artificial variable AV_t^{+}.

The function of node ⑥ is to take in heat from large-scale GSHPs. These are assumed not to be able to lift the temperature, $T^{T}_{`n6',`n7',t}$, of heat energy flow $H_{`n6',`n7',t}$ higher than $\overline{\vartheta^{GSHP}}$ = 80°C. Potential solar-thermal capacity (S2H) injects its heat generation into node ⑦. Node ⑧ functions as a point of heat energy discharging from TES tanks.

All residences are equipped with a heating distribution system (central heating) of their own, which is represented here by the circular flow between nodes ④, ⑨ and ⑩. It is possible to install residential heating facilities behind the substation in node ④, which connects the residence with the district heating network, in order to shift some or the entire heat generation to the residential site. Therefore, node ⑨ allows heat delivery to be boosted by means of a residential heat boiler (RHB) fired with gas or biomass, or by means of a residential electric boiler (REB). Node ⑩ represents the actual point of heat energy withdrawal for space heating, d_t^{SH}, and domestic hot water, d_t^{DHW}. The yearly total of space heating and domestic hot water energy in this node equals the yearly final energy demand of district heating, since no heat energy losses are assumed within residential buildings. Although the equipment and piping of central heating in residences dissipate heat, these losses still contribute to space heating within the building and, hence, are not necessarily interpreted as heat energy losses.

District heating network constraints

This section summarizes the necessary constraints of the heat transmission network. Equations (5.17) and (5.18) indicate the relation between heat energy flows, $H_{nn,n,t}$, and their temperature level for flows in the transmission and residential networks, respectively. In reality, heat energy flows in the district heating network can be influenced by two factors: the mass flow rate or the temperature. In order to avoid non-linearities, mass flow rates are exogenously calibrated parameters and only the temperatures are treated as variables. In case the heat transmission in the district heating network is switched off by means of binary variable X_t^T, constraint (5.19) sets all heat energy flows and respective temperatures to zero. Constraint (5.20) would allow all previous heat energy injected into the district heating network to be cast off.

$$H_{nn,n,t} = c_w \cdot m_t^T \cdot T_{nn,n,t}^T \qquad \forall\ nn \in \mathcal{NT}, n \in \mathcal{NT}, t \tag{5.17}$$

$$H_{nn,n,t} = c_w \cdot m_t^R \cdot T_{nn,n,t}^R \qquad \forall\ nn \in \mathcal{NR}, n \in \mathcal{NR}, t \tag{5.18}$$

$$H_{nn,n,t} \leq X_t^T \cdot M \qquad \forall\ nn \in \mathcal{NT}, n \in \mathcal{NT}, t \tag{5.19}$$

$$AV_t^+ \leq \left(1 - X_t^T\right) \cdot M \qquad \forall\ t \tag{5.20}$$

Constraints (5.21) and (5.22) form the upper bound for the supply flow temperature and the lower bound for the return flow temperature, respectively. Constraint (5.23) ensures that a minimum temperature spread $\underline{\Delta\vartheta}$ is always maintained at the cold end of the aggregated heat exchanger in node ④. For node ⑩ equation (5.24) indicates the relation between the temperature drop from the residential supply to the residential return flow on

the one hand and the space heating and domestic hot water energy demand on the other.

$$T^T_{`n3',`n4',t} \leq X^T_t \cdot \underline{\vartheta^{TS}} \qquad \forall\, t \qquad (5.21)$$

$$T^T_{`n5',`n6',t} \geq X^T_t \cdot \underline{\vartheta^{TR}} \qquad \forall\, t \qquad (5.22)$$

$$T^T_{`n4',`n5',t} + \left(1 - X^T_t\right) \cdot M \geq T^R_{`n10',`n4',t} + \underline{\Delta\vartheta} \qquad \forall\, t \qquad (5.23)$$

$$d^{SH}_t + d^{DHW}_t = c_w \cdot m^R_t \cdot \left(T^R_{`n9',`n10',t} - T^R_{`n10',`n4',t}\right) \qquad \forall\, t \qquad (5.24)$$

Heat transmission supply and return flow losses

Heat transmission losses of the supply and return flow, Q^{TLS}_t and Q^{TLR}_t, respectively, depend on the temperature and ambient temperature of these flows. The bigger this temperature gap, the bigger the transmission losses, as illustrated by equations (5.25a) and (5.25b). The temperature level of the supply or return flow is approximated by the arithmetic mean of the start and end points of transmission. In case the heat transmission network is switched off by the binary variable X^T_t, transmission losses obviously become zero. The parameter c^{TL} is calibrated in such a way that heat transmission losses in the Reference scenario (see next section) amount to about 12% over the year, which is a realistic value for the Berlin district heating network.

$$Q^{TLS}_t = c^{TL} \cdot \left(\frac{T^T_{`n2',`n3',t} + T^T_{`n3',`n4',t}}{2} - X^T_t \cdot \vartheta^a_t\right) \qquad \forall\, t \qquad (5.25a)$$

$$Q^{TLR}_t = c^{TL} \cdot \left(\frac{T^T_{`n4',`n5',t} + T^T_{`n5',`n6',t}}{2} - X^T_t \cdot \vartheta^a_t\right) \qquad \forall\, t \qquad (5.25b)$$

5.4 Scenarios and data

5.4.1 Scenario setup

Table 5.1 provides an overview of the different scenarios and the parameter variations that are computed and juxtaposed in this analysis. Three scenarios are distinguished: the Reference scenario, the business-as-usual (BAU) scenario and the Berlin Energy and Climate Protection Program (BECP) scenario. The Reference scenario allows for the calibration of some model parameters and, since it represents the situation of the energy system in 2015, it serves as a useful comparison with the other simulations. The Reference scenario computes historical data from 2015 and allows no capacity decommissions or investments. All data utilized here is openly accessible in Bloess (2019b). The BAU and BECP scenarios consist of statically computed future situations of the energy system for the years 2020, 2030, and 2050. According to the German Federal Government's political targets, the annual power generation in these years should consist of at least 35%, 50%, and 80% RES, respectively. Assumptions for the German power system, the Berlin power system, and the district heating system are listed separately. The year of each simulation run affects the existing German power plant fleet through decommissioning. According to

the agenda of the Atomic Energy Act (AEA) (which enforces the nuclear energy phase-out in Germany), the available nuclear capacity is to be reduced between 2015 and 2020 and should disappear completely by 2022. Existing capacities other than nuclear power plants are to be exogenously decommissioned in future years according to the year in which they were commissioned and their technical life span. In the BAU and BECP simulation runs, further capacity decommissions as well as investments are determined endogenously. The model allows for new capacity investments into PV, on- and offshore wind power (WPon, WPoff), biomass-fueled ST plants, CC, or GT plants, as well as battery, and power-to-gas storage capacities.

In the BAU scenario, the annual net power demand and district heating demand of the Berlin joint energy system are both assumed to stay constant at 2015 levels with 13.4 $\mathrm{TWh_{el}}$ and 10.4 $\mathrm{TWh_{el}}$, respectively. In the BECP scenario, power and district heating demand develop according to the political targets. Berlin's existing power and heat generation capacities are listed in Table 5.2, which also indicates some capacity modifications according to the scenario and the simulation year. Further decommissions of entire power plant blocks can be determined endogenously. Potential investments into power or heat generation technologies consist of onshore wind and PV power; biomass-fueled conventional, BP or EC CHP plants; gas-fueled conventional CC and GT plants; as wells as CCEC and gas turbine CHP (GTCHP). Power storage investments are available in the form of battery and power-to-gas capacity. For investments into heat-only generation technology, options include biomass or gas-fueled heat boilers either in the heat transmission system (district heating boilers; DHBs) or at the residential sites (residential heat boilers; RHBs). Investments into electric boilers can take place either in the heat transmission system (district heating electrode boilers; DHEBs) or directly at residences (residential electric boilers; REBs). Large-scale ground source heat pumps (GSHPs), solar-thermal generation (S2H), and thermal energy storage (TES) tanks are further potential investments.

The BAU and BECP scenarios differ in terms of additional energy and climate protection policy restrictions. The BECP scenario imposes annual limits of CO_2 emissions. In 2015 the Berlin energy sector emitted nearly 7.1 Mt of CO_2. According to the political targets of the Berlin state government, these emissions are supposed to decrease to 3.9 Mt annually by 2050, as depicted in Figure 5.1 and in Table 5.1. Furthermore, state government policy seeks to enforce a phase-out from coal-generated energy by the end of 2030. In contrast, in the BAU scenario, no emission constraints are imposed.

The technical configurations of the Berlin district heating network are hypothetically modified in order to analyze the adjustments of Berlin's joint power and district heating system to any increased RES penetrations in the national power mix in the future. In the Reference scenario, the district heating network operates at a maximum supply temperature of $\overline{\vartheta^{TS}} = 140$°C and a minimum return temperature of $\underline{\vartheta^{TR}} = 70$°C. In the BAU and BECP scenarios, further combinations of maximum supply and minimum return temperature $\left(\overline{\vartheta^{TS}}; \underline{\vartheta^{TR}}\right)$ are analyzed; these are (130;70), (120;70), (110;60), (100;50), and (90;40). To the best knowledge of the author, no modifications for lowering the supply and return temperature in the Berlin district heating network are currently being planned. Transforming the Berlin district heating network into a 4th generation network would require

Table 5.1: Scenario overview and parameter variations.

		Unit	Reference 2015	BAU scenario 2020	BAU scenario 2030	BAU scenario 2050	BECP scenario 2020	BECP scenario 2030	BECP scenario 2050
German power system:									
power demand w/o Berlin	**exo.**	**TWh_{el}**	501	501	501	501	518	547	569
RES min. share	**exo.**	**%**	29	35	50	80	35	50	80
biomass limit w/o Berlin	**exo.**	**TWh**		57.4	57.4	57.4	57.4	57.4	57.4
nuclear power plants	**exo.**	**MW_{el}**	acc. AEA	acc. AEA	no	no	acc. AEA	no	no
decommissioning	**exo./endo.**	**MW_{el}**	no	block sharp acc. to lifetime/ linear			block sharp acc. to lifetime/ linear		
power investments	**endo.**	**MW_{el}**	no	vRES:	WPon, WPoff, PV		vRES:	WPon, WPoff, PV	
				biomass:	ST		biomass:	ST	
				gas:	CC, GT		gas:	CC, GT	
				storage:	BT, P2G		storage:	BT, P2G	
Berlin power and DH system:									
CO_2 emissions limit	**exo.**	**Mt**	7.0812	no	no	no	7.8	5.625	3.9
biomass limit	**exo.**	**TWh**		2.6	2.6	2.6	2.6	2.6	2.6
Berlin power system:									
power demand Berlin	**exo.**	**TWh_{el}**	13.3	13.3	13.3	13.3	11.9	11.9	10.8
decommissioning	**endo.**	**MW_{el}**	no	block sharp	block sharp	block sharp	block sharp	block sharp	block sharp
power investment	**endo.**	**MW_{el}**	no	vRES:	WPon, PV		vRES:	WPon, PV	
				biomass:	ST, BP, EC		biomass:	ST, BP, EC	
				gas:	CC, CCEC, GT, GTCHP		gas:	CC, CCEC, GT, GTCHP	
				storage:	BT, P2G		storage:	BT, P2G	
power import		**TWh_{el}**	6.6	endo.	endo.	endo.	endo.	endo.	endo.
Berlin DH system:									
DH demand	**exo.**	**TWh_{th}**	10.4	10.4	10.4	10.4	12.2	12.5	9.4
decommissioning	**endo.**	**MW_{th}**	no	only DHB capacity linear			only DHB capacity linear		
heat investment	**endo.**	**MW_{th}**	no	biomass:	DHB, RHB		biomass:	DHB, RHB	
				gas:	DHB, RHB		gas:	DHB, RHB	
				P2H:	DHEB, GSHP, REB		P2H:	DHEB, GSHP, REB	
				solar:	S2H		solar:	S2H	
				storage:	TES		storage:	TES	
Variations in DH system:									
$\overline{\vartheta^{TS}}$		**°C**		140	130	120	110	100	90
$\underline{\vartheta^{TR}}$		**°C**		70	70	70	60	50	40
pumping work		**GWh_{el}**	72.5	subject to calibration			subject to calibration		
heat transmission loss		**%**	12.6	endo.	endo.	endo.	endo.	endo.	endo.

very complex and costly modifications; these could include enlarging the heat exchanger surface in numerous consumer substations, enlarging pipe diameters with adequate thermal insulation, the creation of sub-networks for distribution, more distributed heat plants, increased pump capacity (where made necessary by hydraulic constraints), and accessing locally distributed alternative low temperature heat sources. The concrete technical planning of such modifications and an adequate estimation of the associated costs would require very detailed data about the existing network topography and is beyond the scope of this work. Therefore, all computations with modified maximum supply temperatures must be understood here as part of a hypothetical what-if analysis, that is, as though all necessary investments to enable these temperature levels in the network have already taken place.

Considering all the parameter variations for the different scenarios, a total of 37 different simulation runs are analyzed. This number comprises two different policy scenarios times three future RES penetrations times six different technical configurations of the district heating network, plus the Reference scenario.

5.4.2 Power demand in Germany and Berlin

The total final electric energy demand for Germany and the city state of Berlin in 2015 is provided by reports of official energy statistics services on the national level (BMWi, 2018b) and the state level (AfS BB, 2018b). The hourly power load time series can be derived from historical data provided by the European Network of Transmission System Operators for Electricity (ENTSO-E). National and control-area-wide quarter-hourly power loads are published on the ENTSO-E transparency platform (ENTSO-E, 2018). The Berlin hourly power load is assumed to be congruent with power load variations of the 50Hertz control area, in whose geographical center Berlin is located as the biggest electric energy consumer.

5.4.3 Berlin district heating demand

The total final district heating energy demand for the city of Berlin in 2015 is found in the official statistical energy and CO_2 emissions state reports (AfS BB, 2018b). The district heating energy demand consists of major demand for space heating and minor demand for domestic hot water energy. The latter is assumed to account for 16% of the yearly final district heating energy demand. The space heating demand occurs only within the heating season and depends during that time on hourly ambient temperatures, whereas domestic hot water energy demand follows a standard profile over the entire year derived from Frederiksen and Werner (2014, p. 55). Consequently, the combined hourly district heating load drops significantly during the non-heating season. The German Meteorological Service operates three stations in Berlin for collecting weather data and provides hourly ambient temperatures for each of these (DWD, 2018). The hourly space heating load can be derived from this data by means of the concept of heating degree-hours with a threshold

temperature of 15°C, as depicted by equations (5.26) and (5.27).

$$hdh_{t_h} = \max_{t_h}\left(15\ [°\mathrm{C}] - \vartheta^a_{t_h}; 0\right) \qquad \forall\ t_h \tag{5.26}$$

$$d^{SH}_t = (1 - 16\%) \cdot d^{DH} \cdot \frac{hdh_t}{\sum_{tt_h} hdh_{tt}} \qquad \forall\ t \tag{5.27}$$

5.4.4 Variable RES time series

The ENTSO-E transparency platform publishes historical data about aggregated installed capacities for various technology types and their actual generation in quarter-hourly resolution nationwide and for each control area in Germany (ENTSO-E, 2018). With this data, hourly capacity factors for power generation from onshore and offshore wind power, PV, and run-of-river hydro power can be derived for Germany in 2015. For the little wind power and PV capacity used in the city of Berlin, the respective data from the surrounding control area 50Hertz is used.

5.4.5 Existing plants and new technologies

The data about the existing power plant fleet originates from the official German list of power plants published by the German Federal Network Agency (BNA) (BNetzA, 2018). This list is further edited and combined with additional data from other official sources that has been compiled by the OPSD (2018) project (OPSD). Modeling Berlin's joint power and district heating system requires some extra data, which is summarized in Table 5.2. Concerning existing CHP plants, the power-over-heat ratio, σ, and the power-loss-coefficient, β, are derived from this data according to relations (5.28) and (5.29).

$$\sigma_{p,i,f} = \frac{\overline{g}_{p,i,f}}{\overline{q}_{p,i,f}} \qquad \forall\ p, i \mathrel{\hat{=}} BP, i \mathrel{\hat{=}} GTCHP, f \tag{5.28a}$$

$$\sigma_{p,i,f} = \frac{\frac{\eta_{p,i,f}}{\eta^{cm}_{p,i,f}} \cdot \overline{g}_{p,i,f} - \overline{q}_{p,i,f}}{\overline{q}_{p,i,f}} \qquad \forall\ p, i \mathrel{\hat{=}} EC, i \mathrel{\hat{=}} CCEC, f \tag{5.28b}$$

$$\beta_{p,i,f} = \frac{\eta^{cm}_{p,i,f}}{\eta_{p,i,f}} \cdot (1 + \sigma_{p,i,f}) - \sigma_{p,i,f} \qquad \forall\ p, i \mathrel{\hat{=}} EC, i \mathrel{\hat{=}} CCEC, f \tag{5.29a}$$

$$\beta_{p,i,f} = 0 \qquad \forall\ p, i \mathrel{\hat{=}} GTCHP, f \tag{5.29b}$$

Table 5.3 summarizes all of the assumptions concerning economic or technical properties for existing as well as potentially installable technology capacities. The power-over-heat ratio, σ, for new CHP plants is assumed according to relation (5.30). The power-loss-coefficient, β, for new CHP plants can then be derived by means of relation (5.29). For plants based on steam cycles, maximum ramp rates for load changes up and down are

Table 5.2: Power and heat plants operating in Berlin.

Name	BNA	Technology	Fuel	Start year	$\overline{g}_{p,i,f}$	$\overline{q}_{p,i,f}$	$\eta_{p,i,f}$ / $(\eta^{cm}_{p,i,f})$	Reference/ BAU/ BECP
					$\mathbf{MW_{el}}$	$\mathbf{MW_{th}}$	%	
HKW Klingenberg	BNA0081	BP	lignite	1981	164	590	80	✔/ ✘/ ✘
HKW Moabit A	BNA0085a	EC	coal	1990	89	136	80 / (40)	✔/ ✔/ ★
HKW Mobait GT	BNA0085b	GT	oil	1971	51		30	✔/ ✔/ ✔
HKW Reuter C	BNA0082	EC	coal	1969	124	244	80 / (35)	✔/ ✔/ ★
HKW Reuter West D	BNA0086	EC	coal	1987	282	363	80 / (40)	✔/ ✔/ ★
HKW Reuter West E	BNA0087	EC	coal	1988	282	363	80 / (40)	✔/ ✔/ ★
HKW Wilmersdorf 1	BNA0083	GTCHP	oil	1977	93	110	78 / (36)	✔/ ✔/ ✔
HKW Wilmersdorf 2	BNA0083	GTCHP	oil	1977	93	110	78 / (36)	✔/ ✔/ ✔
HKW Wilmersdorf 3	BNA0083	GTCHP	oil	1977	93	110	78 / (36)	✔/ ✔/ ✔
MHKW Reuter M	BNA0084	BP	waste	1998	36	100	80	✔/ ✔/ ✔
HKW Charlottenburg	BNA0074	GTCHP	gas	1975	211	300	80 / (33)	✔/ ✔/ ✔
HKW Lichterfelde 1	BNA0075	EC	gas	1972	144	240	70 / (38)	✔/ ✔/ ✔
HKW Lichterfelde 2	BNA0080	EC	gas	1973	144	240	70 / (38)	✔/ ✘/ ✘
HKW Lichterfelde 3	BNA0076	EC	gas	1974	144	240	70 / (38)	✔/ ✔/ ✔
HKW Lichterfelde	unknown	CCEC	gas	2018	300	230	90 / (65)	✘/ ✔/ ✔
HKW HW Lichterfelde		DHB	gas	2018		360	95	✘/ ✔/ ✔
HKW Mitte	BNA0073	CCEC	gas	1996	444	398	90 / (52)	✔/ ✔/ ✔
HKW HW Mitte		DHB	gas			282	95	✔/ ✔/ ✔
HKW Scharnhorststr.	unknown	GTCHP	gas	2018	12	40	80 / (18)	✘/ ✔/ ✔
HW Scharnhorststr.		DHB	gas			160	95	✔/ ✔/ ✔
nameless agg.		DHB	gas			420	95	✔/ ✔/ ✔
HHKW Berlin-Neukölln	BNA0068	EC	biomass	2005	20	65	80 / (20)	✔/ ✔/ ✔
HHKW HW Berlin-Neukölln		DHB	gas			99	95	✔/ ✔/ ✔
BHKW Märkisches Viertel		BP	biomass		5	18	80	✔/ ✔/ ✔
Berlin wind power agg.		WPon	wind		12			✔/ ✔/ ✔
Berlin PV agg.		PV	solar		87			✔/ ✔/ ✔

✔: included, ✘: decommissioned, ★: decommissioned by the end of 2030 acc. to BECP
Source: Based on BNetzA (2018), OPSD (2018) and own research.

assumed to be 0.3 for existing plants and 0.6 for new capacity installations.

$$\sigma_{p,i,f} = \begin{cases} 0.7 & \forall\ p, i \mathrel{\hat{=}} BP, i \mathrel{\hat{=}} EC, f \\ 0.9 & \forall\ p, i \mathrel{\hat{=}} CCEC, f \\ \frac{\eta^{cm}_{p,i,f}}{\eta_{p,i,f} - \eta^{cm}_{p,i,f}} & \forall\ p, i \mathrel{\hat{=}} GTCHP, f \end{cases} \tag{5.30}$$

Table 5.4 lists all assumptions about the prices and carbon contents of different types of fuel and the development of the CO_2 emission price.

5.4.6 Mass flow rate and pumping work of the heat transmission network

The heat energy flow in the heat transmission network is based on the relation (5.31). In this relation the transmitted energy depends on the mass flow rate $\dot{m}$ and its temperature

Table 5.3: Technical and economic technology assumptions.

Fuel	Technology	spec. Investment cost		fixed O&M cost		var. O&M cost	Ramping cost	Efficiency new $\eta_{p,i,f}$ / $\left(\eta^{cm}_{p,i,f}\right)$	Economic lifetime	Technical lifetime
		€/kW		€/kW		€/MW	€/MW	%	years	years
		2015	2050	2015	2050					
power generation technologies:										
uranium	ST			100		8.5	200			
lignite	ST			60		7.0	100			40
	BP			66		7.7	100	85		
coal	ST			50		6.0	50	45	30	40
	BP			55		6.6	50	85	30	40
	EC			55		6.6	50	85 / (45)	30	40
oil	ST			15		3.0	50			40
	CC			25		4.0	20			35
	GT			15		2.0	20			35
	GTCHP			16.5		2.2	20			35
waste	ST			100		7.0	50			40
	BP			110		7.7	50			40
gas	ST			15		3.0	50			40
	EC			30		4.0	50			40
	CC	800	671	20	17	3.0	20	65	30	35
	EC	960	806	22	18	3.3	20	90 / (65)	30	35
	GT	550	461	15	13	2.0	20	35	30	35
	GTCHP	715	600	16.5	14	2.2	20	90 / (35)	30	35
biomass	ST	2,400	2,014	100	84	7.0	50	42	30	40
	EC	2,880	2,417	110	92	7.7	20	85 / (42)	30	40
	BP	2,400	2,014	110	92	7.7	20	85	30	40
wind	WPon	1,063	747	43	30				20	
	WPoff	2,300	1,618	100	70				20	
solar	PV	600	422	20	14				20	
hydro	ROR			60						
	PSP			20						
storage	BT	150	106	3.5	2.4			90	20	
	P2G	1,850	1,301	92.5	65			70	20	
heat generation technologies:										
gas	DHB	220	184	6.5	5.5	1.0		105	30	
	RHB	300	252	10	8.4	2.0		105	20	
biomass	DHB	263	220	7.8	6.5	1.2		101	30	
	RHB	400	336	15	12.6	4.0		101	15	
power	DHEB	170	143	1.7	1.4			98	20	
	REB	200	168					98	20	
	GSHP	1,500	1,055	5.5	3.8	2.0			20	
solar	S2H1	200	141						20	
	S2H2	160	113						20	
storage	TES	0.3	0.3					95	30	

Source: Gerbaulet and Lorenz (2017) and Schröder et al. (2013) and own estimations.

T. c_w denotes the specific heat capacity of water.

$$\dot{H} = c_w \cdot \dot{m} \cdot T \tag{5.31}$$

In order to avoid non-linearities in the computations, only the temperature is treated as an endogenously determined variable. The mass flow rate is a parameter that needs to be determined exogenously. Thus, the parameters for the mass flow rate of the district heating transmission network, m_t^T, and of the residential distribution network, m_t^R, must be determined for the model formulated in Section 5.3. The residential mass flow rate is determined by formulation (5.32) using estimates for the residential supply and return temperatures ϑ_t^{RSe} and ϑ_t^{RRe}, respectively. Figure 5.7 shows these estimates for supply and return temperatures, which are dependent on ambient temperature as they occur in reality according to existing studies. The correction factor cf^R is calibrated by means of the settings of the Reference scenario in such a way that in the hour of maximum load the

Table 5.4: Fuel price, carbon content, and emission price.

Fuel	**Carbon content** t_{CO_2}/MWh	**Price** €/MWh			
		2015	**2020**	**2030**	**2050**
uranium		3.2	3.4		
lignite	0.404	3.0	4.3	5.6	7.6
coal	0.337	6.6	7.6	8.4	9.9
oil	0.280	21.1	35.5	48.3	76.9
waste	0.144	8.1	9.0	10.8	14.4
gas	0.201	15.0	20.1	26.4	37.6
biomass		8.1	9.0	10.8	14.4
Emission		**Price in** €/t_{CO_2}			
		2015	**2020**	**2030**	**2050**
CO_2		7.2	13.5	29.4	58.1

Source: Based on 50Hertz et al. (2019) and Gerbaulet and Lorenz (2017).

endogenous residential supply temperature $T^R_{nn,n,t}$ stays just below a realistic maximum of 90°C.

$$m^R_t = c_w \cdot \frac{d^{SH}_t + d^{DHW}_t}{\vartheta^{RSe}_t - \vartheta^{RRe}_t} \cdot cf^R \qquad \forall\ t \tag{5.32}$$

The district heating transmission mass flow m^T_t is determined differently. First, it is assumed that no heat energy accumulation is possible in the district heating network piping. Then, an hourly reference mass flow $m^{T\ ref}_t$ is determined analogously to the residential mass flow according to (5.33). Here, as above, there are realistic estimates based on existing studies are used to calculate the transmission supply and return temperatures, ϑ^{TSe}_t and ϑ^{TRe}_t, respectively, as depicted in Figure 5.7. Furthermore, in the heat transmission network illustrated in Figure 5.5, the mass flow balance must be maintained for every node and for every hour. This means that all water mass flows entering a node must equal the mass flows leaving the node. When assuming the possibility of heat accumulation in the district heating network piping by lifting the temperature level higher than required by the heat load, previous heat energy surpluses arrive at node ⑥ within the heat energy flow $H_{`n5',`n6',t-1}$ and are passed on to the outflowing heat energy one time step later $H_{`n6',`n7',t}$. This requires the inflowing water mass of a previous time step m^T_{t-1} to equal the outflowing water mass m^T_t. Consequently, in order to enable heat accumulation in the model, all mass flows must be equal in every time step t in this model, otherwise the mass flow balance cannot be maintained in node ⑥. The mass flow m^T_t in the heat transmission network can then be determined by the arithmetic mean of all reference mass flows $m^{T\ ref}_t$ according to (5.34). The correction factor $cf^T\left(\overline{\vartheta^{TS}};\underline{\vartheta^{TR}}\right)$ must be calibrated for each of the different heat transmission network configurations, which consist of the various combinations of the

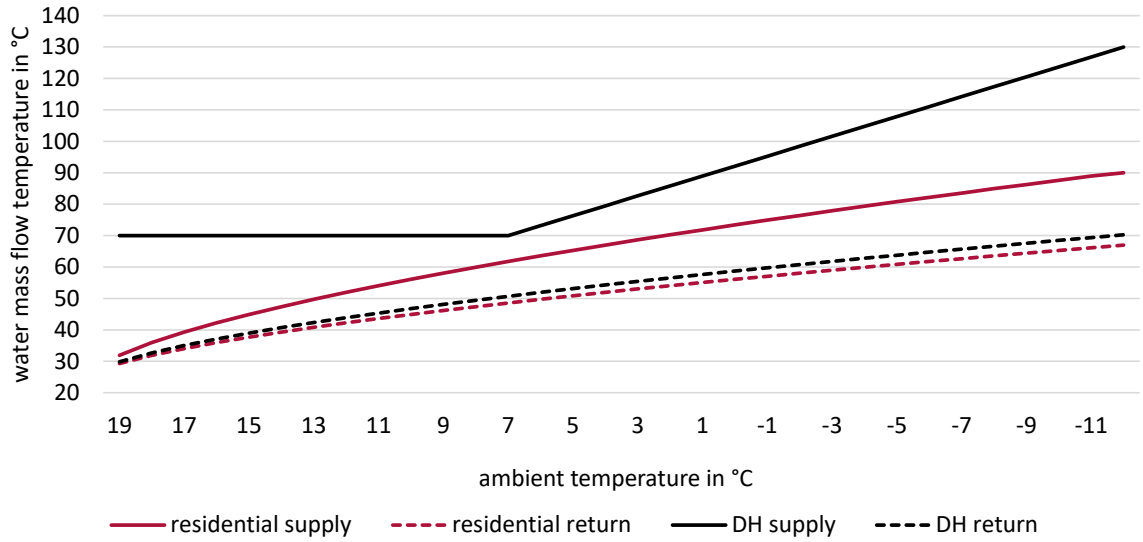


Figure 5.7: Supply and return temperatures of water mass flow in residential distribution and district heating network.

Source: Based on Scholz (2013).

maximum transmission supply temperatures $\overline{\vartheta^{TS}}$ and the minimum transmission return temperatures $\underline{\vartheta^{TR}}$ considered in this analysis. It is calibrated in such a way that, without the possibility of heat accumulation, the highest flow temperature $T^{T}_{`n2',`n3',t}$ of heat energy flow $H_{`n2',`n3',t}$ stays just below the maximum transmission supply temperature $\overline{\vartheta^{TS}}$.

$$m_t^{T\ ref} = c_w \cdot \frac{d_t^{SH} + d_t^{DHW}}{\vartheta_t^{TSe} - \vartheta_t^{TRe}} \cdot cf^{T\ ref} \qquad \forall\ t \tag{5.33}$$

$$m_t^{T} = \frac{\sum_{tt} m_{tt}^{T\ ref}}{\sum_{tt} 1} \cdot cf^{T}\left(\overline{\vartheta^{TS}}, \underline{\vartheta^{TR}}\right) \qquad \forall\ t \tag{5.34}$$

Having obtained the hourly water mass flow in the heat transmission network, the hourly pumping work d_t^{PW} can be calculated. According to relation (5.35), the pumping work grows by a power of three of the pumped water mass flow. The pumping work efficiency is assumed to be $\eta^{PW} = 0.7$ and the network resistance NR is calibrated in such a way that in the Reference scenario the annual pumping work amounts to 0.7% of the supplied annual final district heating energy. The resulting annual pumping work is subtracted from Berlin's annual conventional electricity demand.

$$d_t^{PW} = \frac{NR}{\rho \cdot \eta^{PW}} \cdot m_t^{T3} \qquad \forall\ t \tag{5.35}$$

5.5 Results

5.5.1 Total system costs and costs per unit of exergy production

Figure 5.8 presents Berlin's overall cost structure, which consists of operation, power import, fixed O&M, and investment costs for the Reference scenario and for the BAU and BECP scenarios each with a district heating maximum supply temperature of 140°C and 90°C, respectively. Cost increases are mainly in operating cots due to the assumed increase of fuel and emission costs. In the BAU scenario, costs increase continuously up to an RES system penetration of 80% in 2050, since Berlin's power and district heating demands are assumed to stay constant. In contrast, the BECP scenario assumes decreasing demand in the long run so that total costs are already declining in 2050 when 80% RES penetration is reached.

In order to cancel out the effects of different assumed demand developments, the analysis in Figure 5.9 illustrates the costs for each simulation run in the form of cost per unit of exergy production (COPEX) in Berlin's power and district heating systems. This indicator sums up all of the costs involved in the actual production of electric and thermal energy that takes place within the Berlin energy system. The power generation costs of imports are not included. These costs are divided by the amount of yearly net exergy production in the form of electricity and heat. This approach is chosen for two reasons. First, since power imports are not counted, the model only measures the costs of keeping Berlin's energy infrastructure running. Second, relating the costs to the exergy production instead of the energy production allows the different energy quality of electricity and heat to be taken into account and maintains comparability in the event that heat production becomes dominant over local Berlin power production. For further details about calculating COPEX

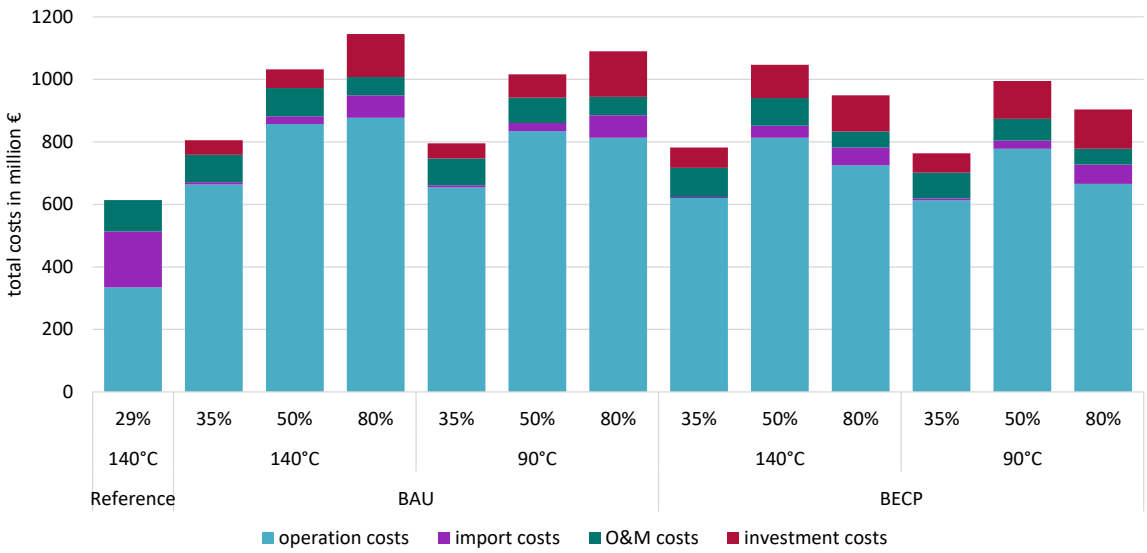


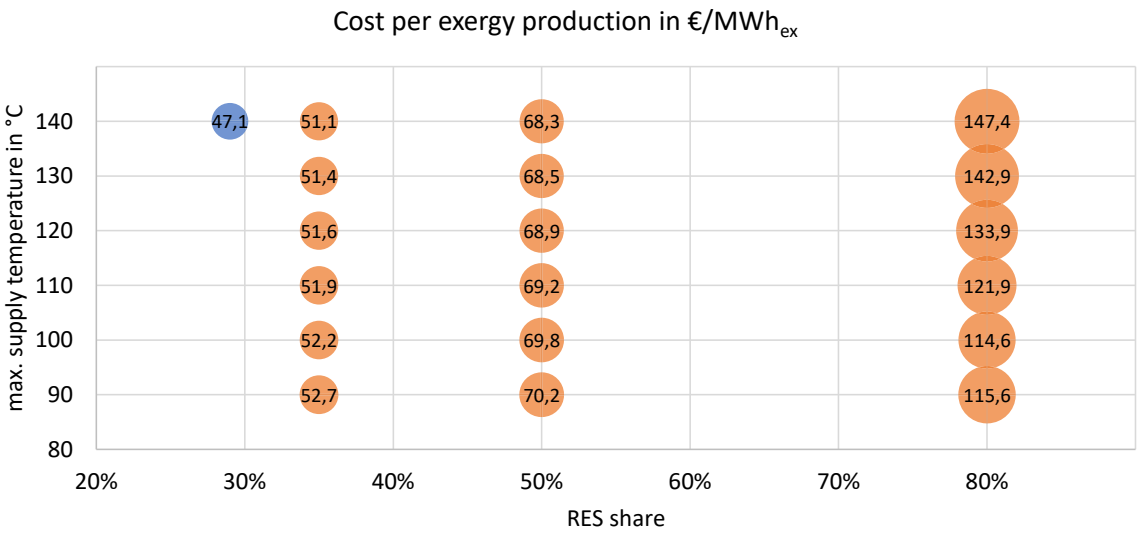
Figure 5.8: Cost structure.

refer to Appendix D.3.

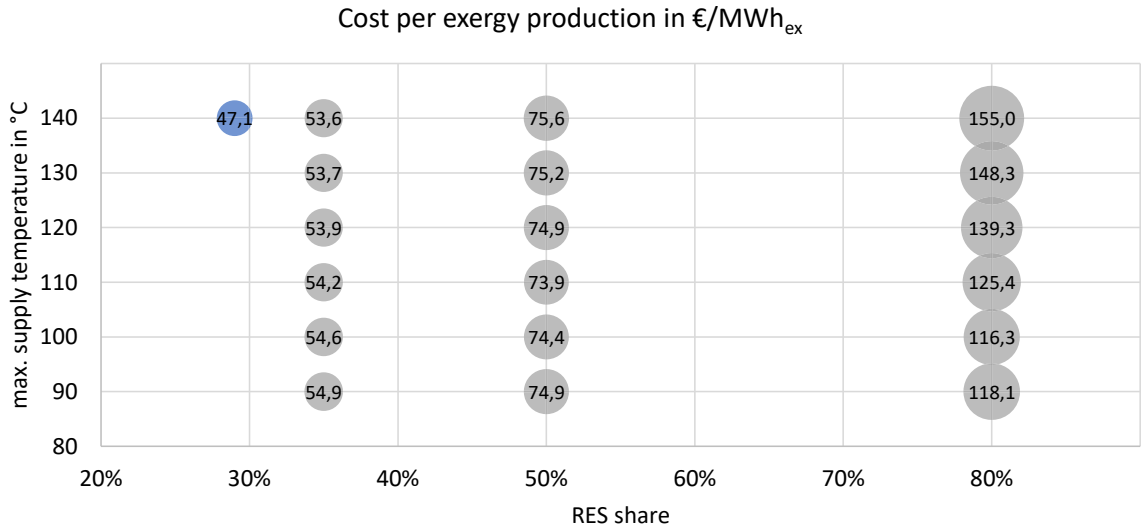
In the Reference scenario representing the year 2015, each megawatt hour of exergy of final energy produced in Berlin costs about 47.1 €. Germany's power production mix in 2015 consisted of 29% RES. Recall that, in the model's Reference scenario, no decommissioning of existing plants or investments into new power generation capacity is allowed. For 2020, Germany's power generation mix is supposed to have a minimum of 35% RES penetration. If the Berlin district heating system remains at the same maximum supply temperature level, the costs per exergy provision would rise to 51.1 €/$\mathrm{MWh_{ex}}$ in the BAU scenario and to 53.6 €/$\mathrm{MWh_{ex}}$ in the BECP scenario, as shown by Figures 5.9a and 5.9b, respectively. The increase is explained by rearrangements of power and heat generation capacity and operation. Expendable and older capacities are decommissioned, which leads to savings in fixed O&M costs. Moreover, investments in newer and more efficient technology leads to savings in operating costs. Because they happened after 2015, some of these capacity decommissions and investments are exogenously determined, such as the decommissioning of the only Berlin lignite CHP plant with low operating costs and the commissioning of a large new CCEC plant with more costly fuel. Other capacity decommissions and investments are endogenously determined by the model. Furthermore, the use of power-to-heat decreases the net exergy production in the form of electricity, which also leads to higher a COPEX.

Figure 5.9a shows that, by increasing the minimum RES penetration in the German power generation mix from 35% to 80% and keeping the maximum supply temperature of the Berlin district heating system at the same level, the costs per exergy provision rise from 51.1 €/$\mathrm{MWh_{ex}}$ to 147.4 €/$\mathrm{MWh_{ex}}$ in the BAU scenario. At 50% RES penetration, the use of electricity for power-to-heat becomes more important and the rise of imports leads to a lower utilization of existing capital in Berlin, which decreases net electric exergy production. Both effects become substantially stronger at an RES penetration of 80% and necessarily lead to an increased COPEX. In contrast, Berlin's exergy production in the form of heat decreases only slightly over the course of increasing RES penetration, since demand is assumed to stay constant in the BAU scenario and district heating must be generated locally. Also, the influence of heat exergy production on COPEX in terms of quantity is substantially lower, since heat exergy represents only a fraction of heat energy produced, whereas nearly all electric energy production represents exergy. A similar but somewhat stronger observation is made concerning the BECP scenario in Figure 5.9b, where the COPEX rises from 53.6 to 155 €/$\mathrm{MWh_{ex}}$; the only difference is that cheap power generation based on coal has to be reduced at the 35% and 50% RES penetration levels in order to fulfill the additional emission reduction targets of the BECP. Instead, gas — which is less carbon emission intensive but more costly — is used as fuel. At 80% RES penetration in 2050, both the BAU and BECP scenarios renounce coal based power generation imposed by the national coal exit energy policy. Still, the BAU scenario can achieve a significantly lower COPEX than the BECP scenario, which must rely on more costly power and heat generation technology to meet its emission targets.

Furthermore, the COPEX for each level of RES penetration changes when the maximum supply temperature of the Berlin district heating network is decreased from from



(a) Costs per exergy production in Berlin in Reference and BAU scenario.



(b) Costs per exergy production in Berlin in Reference and BECP scenario.

Figure 5.9: Costs per exergy production in Berlin including investment, fixed O&M, and operating costs.

140°C to 90°C. There is only a slight change in both the BAU and BECP scenarios when the RES penetration level is at 35% and 50%. However, there is a significant decrease in COPEX from 147.4 €/MWh_{ex} to 115.6 €/MWh_{ex} in the BAU scenario and from 155 €/MWh_{ex} to 118.1 €/MWh_{ex} in the BECP scenario when the maximum supply temperature is reduced at an 80% RES system penetration. In this case, several effects of the development of the COPEX work against each other. First, when reducing the maximum supply temperature, transmission losses decrease. Second, exergy production in the form of heat decreases, since more heat energy is generated at somewhat lower temperature levels. This reduces the net exergy production in the form of heat up to minus 30% when running the district heating network at a maximum of 90°C compared to 140°C. Third, and most significantly, the electric net exergy production increases over the course of decreasing maximum supply temperature, because imports and power demands for power-to-heat decrease. Unlike the first and third effect, the second effect actually leads to an increased COPEX; however, the third effect is more dominant and determines the development of a decreasing COPEX when the maximum supply temperature is lowered. The following analysis clarifies these developments in more detail.

5.5.2 Power-to-heat demand

Figure 5.10 illustrates the power demand for power-to-heat and for the required pumping work in the district heating network. Berlin's conventional power and district heating demands are not indicated here, since they are exogenously determined according to Table 5.1. The pumping work required for keeping the district heating network running is estimated to amount to 73 GWh_{el} annually in the Reference scenario. Reducing the maximum supply temperature to 130°C results in lower transmission losses. This allows lower mass flow rates in the piping network, which enables pumping work to be reduced to 59 GWh_{el}. However, further reduction of the maximum supply temperature also leads to a smaller temperature spread between the supply and return temperatures. Therefore, the mass flow rate must be increased in order to deliver the same amount of heat energy and therefore more pumping work is also required. Recall that pumping work grows exponentially by the power of three of the mass flow rate. Reducing the maximum supply temperature to 90°C then requires 120 GWh_{el} per year. In the BAU scenario, pumping work stays constant over the course of increasing RES penetration, because the district heating demand is assumed to stay constant. In the BECP scenario, pumping work changes according to the assumed district heating demand. Moreover, pumping work could be reduced compared to the Reference scenario through a shift in heat delivery from district heating supply to residential heating by means of residential electric or gas boiler capacities either entirely or during certain hours of the year. Yet, none of the model computations show such decisions.

Nevertheless, the development of pumping work in the Berlin district heating system is very small compared to the increase of the additionally required power for power-to-heat. With increasing RES penetration, more power-to-heat is used in Berlin's district heating supply. In the BECP scenario, the power-to-heat demand increases to nearly

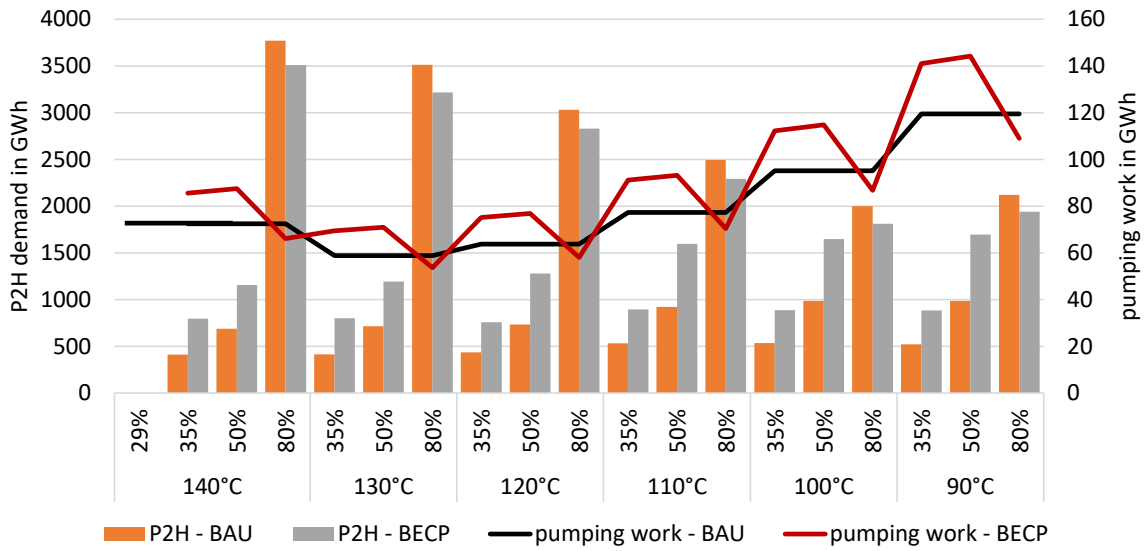


Figure 5.10: Power-to-heat demand development and pumping work.

0.8 TWh_{el}, 1.2 TWh_{el}, and 3.5 TWh_{el} at 35%, 50%, and 80% RES penetration, respectively. Noteworthy is the three-fold increase from 1.2 to 3.5 TWh_{el} when RES penetration rises from 50% to 80%. A similar pattern is observed when simulating the maximum supply temperature at 140°C, 130°C, and 120°C. Running the system at a maximum 110°C, 100°C, and 90°C reveals higher demands for power-to-heat compared to the higher maximum supply temperatures of around 1.7 TWh_{el} at an RES penetration of 50%. Yet, at RES penetrations of 80%, power-to-heat demand is significantly lower at the lower maximum supply temperatures. For instance, when the district heating system runs at a maximum of 90°C, the power-to-heat demand at 80% RES penetration reaches only 1.9 TWh_{el} per year instead of 3.5 TWh_{el}. The reason for this is the substantial deployment of heat pumps. These can be used significantly more frequently when network temperatures are lowered and can generate more heat out of less power compared to electric boilers. The BAU and BECP scenarios show the same development of power-to-heat demand, with the latter always indicating a higher demand at 35% and 50% RES penetration. At 80% RES penetration the BAU scenario shows higher use of power for heating.

5.5.3 Heat transmission losses

Transmission losses are modeled endogenously in such a way that higher temperature spreads between the supply and return piping temperatures to the ambient temperature result in higher transmission losses. The model is calibrated in the Reference scenario so that about 12.1% of the heat centrally generated and injected into Berlin's district heating network is lost. While network transformations that allow lower maximum supply temperatures of as low as 90°C enable the reduction of transmission losses, the effect in most computations is still fairly small. The largest reduction of 3.5 percentage points down to

8.6% is achieved in the BECP scenario at 50% RES penetration and 90°C maximum supply temperature. Since transmission losses amount for only a small part of total costs, this efficiency improvement has a minor impact on overall operating and investment decisions.

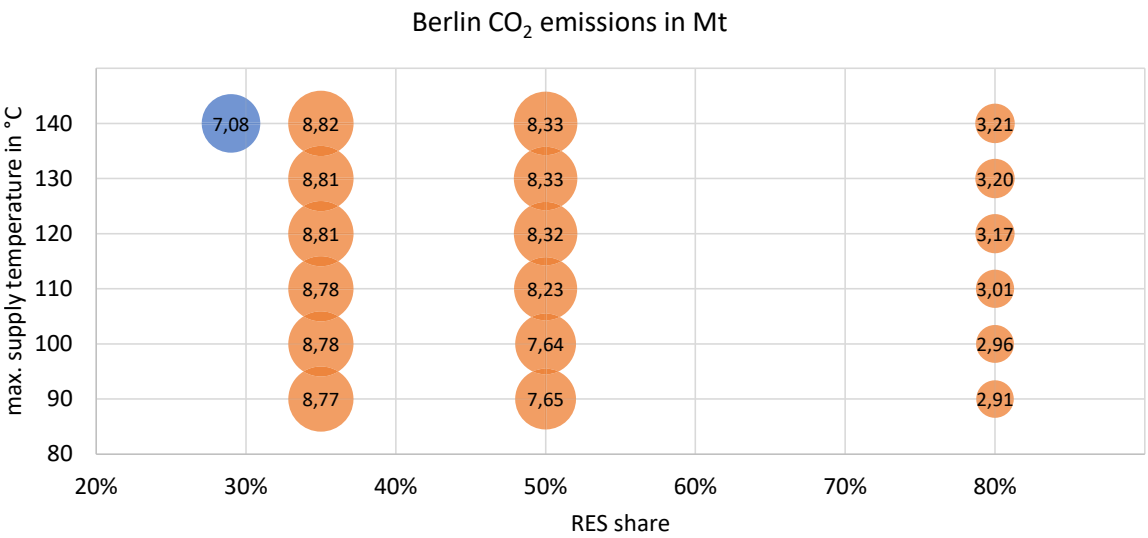
5.5.4 CO_2 emissions development

The resulting CO_2 emissions are depicted in Figure 5.11a for the BAU scenario and in Figure 5.11b for the BECP scenario. If no energy and climate policy were introduced (as in the BAU scenario) and the maximum supply temperature were to stay at 140°C, emissions would rise from 7.1 Mt in the 2015 Reference scenario to 8.82 Mt and 8.33 Mt in the 35% and 50% RES penetration simulations. Later, at the 80% RES penetration level, emissions would drop automatically to 3.21 Mt and would consequently undercut the long-term emission target of yearly 3.9 Mt in 2050 as formulated by Berlin's energy and climate protection policy. This is achieved due to the decommissioning of coal-fueled CHP plants according to the national coal exit policy. As Figure 5.11 shows, further but somewhat smaller emission reductions are achieved by reducing the maximum supply temperature down to 90°C. The CO_2 emissions constraints imposed on the model by the BECP scenario are binding when RES system penetration is 35% and 50%. At 80% RES penetration, the endogenous investment and dispatch decisions can undercut the emission target of 3.9 Mt in 2050 and can get down to 2.63 Mt at a maximum supply temperature of 140°C. This undercutting is even stronger (down to 2.35 Mt) when the district heating maximum supply temperature is lowered to 90°C.

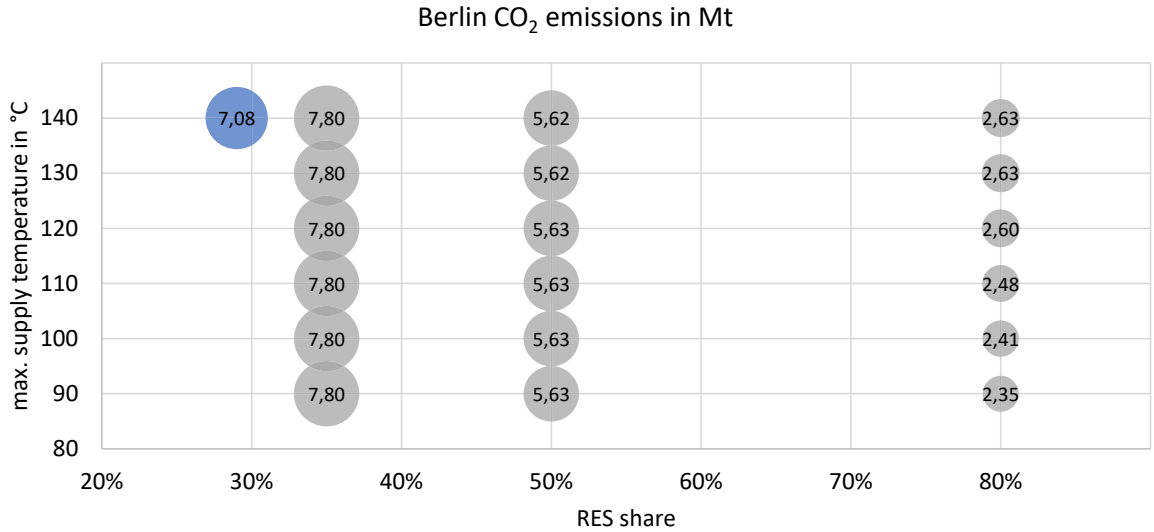
5.5.5 Development of power capacity and generation

Figure 5.12 shows Berlin's power generation capacity composition (Figure 5.12a) and generation mix (Figure 5.12b) for the Reference, BAU, and BECP scenarios at the different levels of RES penetration of the German power system. For brevity, in this and the following subsections, results are presented only for those simulation runs in which the district heating network has a maximum supply temperature of either 140°C or 90°C. In the BAU scenario, all CHP plants based on coal are maintained at 35% and 50% RES penetration in 2020 and 2030, respectively. In 2050, at 80% RES penetration, they are exogenously taken out of the computations due to the national coal exit policy, which provides for the end of coal usage by 2038. When lowering the maximum supply temperature to 90°C, the oldest coal-fueled CHP plant (with 124 MW_{el}) is endogenously decommissioned at 50% RES penetration, since there are more economical alternatives. Since the emission constraint of Berlin's energy policy allows even higher emissions in 2020 than those already achieved in 2015, all coal plants are maintained at 35% RES penetration in the BECP scenario. At 50% RES penetration the oldest coal plant is decommissioned at 140°C maximum supply temperature. Lowering it to 90°C enables 495 MW_{el} of the existing 777 MW_{el} coal-fueled CHP fleet to be economically decommissioned.

Concerning the role of oil in the Berlin power system, the simulation runs show a clear direction. Berlin's oil-fueled gas turbines were built during a time in which it was important to maintain local security of supply. All simulation runs indicate their complete

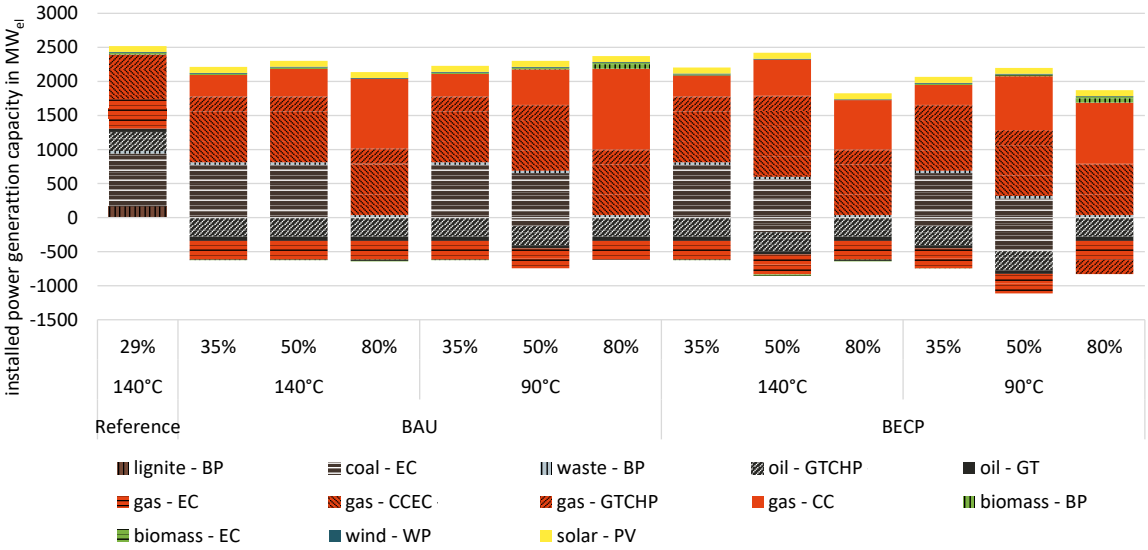


(a) CO_2 emissions in Reference and BAU scenarios.

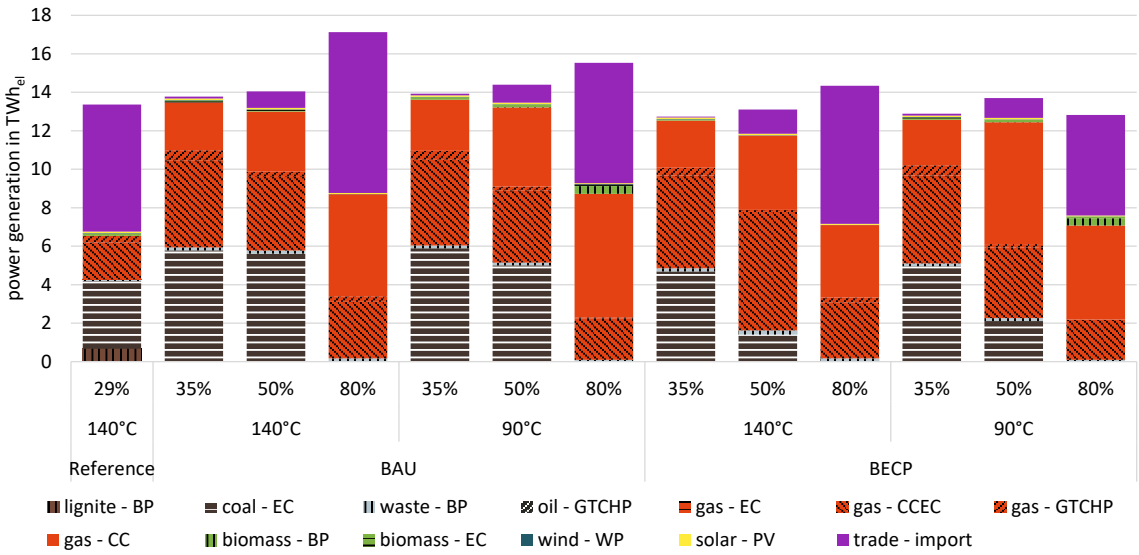


(b) CO_2 emissions in Reference and BECP scenarios.

Figure 5.11: CO_2 emissions development.



(a) Power generation capacity.



(b) Power generation.

Figure 5.12: Power generation capacity and yearly generation.

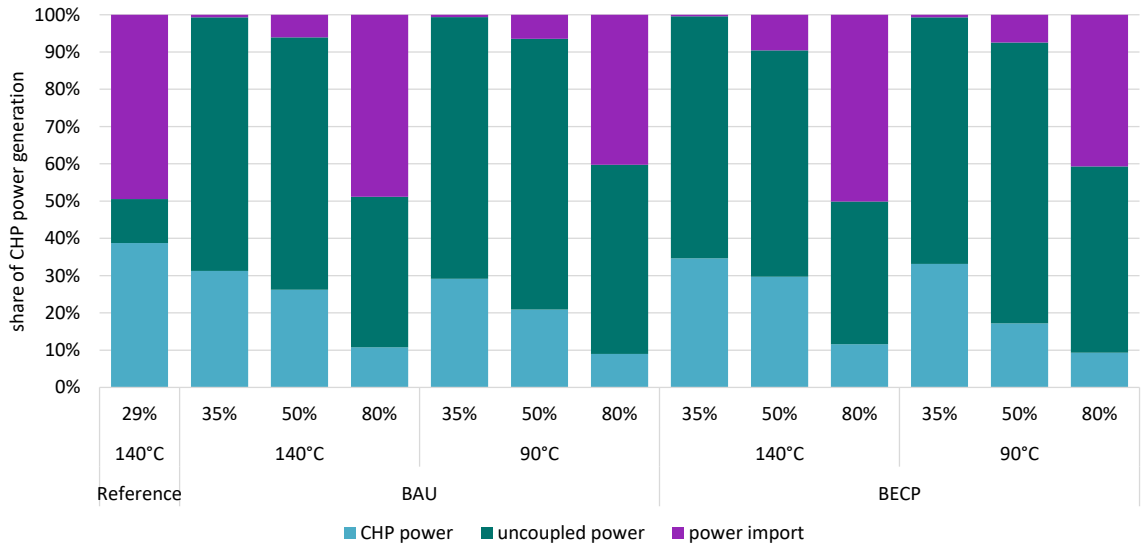


Figure 5.13: Shares of Berlin's power supply by CHP generation, uncoupled generation, and power imports.

decommissioning for the future. Moreover, the same decision is true for all old gas-fueled extraction-condensation steam turbines. In contrast, the CHP gas turbine and combined-cycle turbines with extraction-condensation (CCEC) are maintained in all runs of the simulation. Yet, the simulations clearly show no further investments into any of these technologies, which stands in opposition to the objectives of the Berlin Energy and Climate Protection Program. The only noteworthy exception here is the BECP scenario at 140°C maximum supply temperature and 50% RES penetration, in which CCEC capacity is expanded by 222 MW_{el}. To a greater degree all runs of the simulation indicate substantial investments into combined-cycle gas turbines that generate power only. These expansions are most pronounced in the BAU scenario at a maximum supply temperature of 90°C, with 329 MW_{el}, 522 MW_{el}, and 1,182 MW_{el} at RES penetration levels of 35%, 50%, and 80%, respectively. In the BECP scenario, the expansion is smaller at the same maximum temperature level owing to a decreasing demand for conventional power, with only 219 MW_{el}, 790 MW_{el}, and 895 MW_{el}. In general, the expansion tends to be stronger with decreasing maximum supply temperature, because power-to-heat capacities also increase and more back-up capacity is required.

Concerning the use of local RES for electricity as aimed for by the Berlin Energy and Climate Protection Program, no additional investments into wind power or PV are envisaged. Concerning the role of biomass for power generation the simulations show no clear direction. Some simulations even show the decommissioning of biomass-fueled CHP capacity in order to save the limited biomass resources for heat generation. At 80% RES penetration and a 90°C maximum supply temperature, the BAU and BECP scenarios show a small expansion of about 60 MW_{el} in biomass-fueled back-pressure steam-turbine capacity.

Auxiliary technologies that are also highlighted by the BECP to assist in Berlin's energy

infrastructure, such as battery storage or power-to-gas, do not appear among the model's investment decisions.

An analysis of Berlin's actual power generation in Figure 5.12b reveals that total generation clearly increases with increasing RES penetration in all simulation runs. Since conventional power demand is assumed to stay constant in the BAU scenario, total supply (which includes power imports) rises from 13.4 TWh_{el} in the Reference scenario to 17.1 TWh_{el} in the BAU scenario at an 80% RES penetration and with 140°C maximum supply temperature due to the use of power-to-heat. In contrast, in the BECP scenario total supply stays around the 2015 levels of the Reference scenario despite the use of power-to-heat and thanks to decreasing demands of conventional power and district heating. Unlike the BECP scenario, which is constrained by the emission reduction target, the BAU scenario increases coal based power generation compared to the Reference scenario at both 35% and 50% RES penetration levels. Furthermore, it expands gas-fueled power generation in the existing CCEC plants and in additional CC plants in order to substitute lignite based power generation and costly imports. Note that not all power generation in CCEC plants is necessarily cogenerated with district heating supply, as these can be also operated as conventional CC plants that generate power only. Therefore, Figure 5.13 illustrates the share of power supply originating from CHP generation, uncoupled generation, and imports. According to this figure, the share of CHP power generation decreases with increasing RES penetration from 39% in the Reference scenario to about 10% at 80% RES penetration in all simulation runs, although power generation in coal-fueled extraction-condensation steam-cycle plants or combined-cycle extraction-condensation plants might be expanded as depicted in Figure 5.12b. This means that the existing CHP plants are operated more frequently in condensation mode and that power is generated conventionally. This effect is slightly stronger when lowering the maximum supply temperature. More CHP generation, which the BECP aims to achieve, does not prove to be an economical objective. Instead, the share of uncoupled power generation and imports are substantially increased. Especially at an RES penetration of 80% do imports make up a significant share of the Berlin power supply.

It can therefore be stated that CHP power generation declines with increasing RES penetration and when reducing the maximum supply temperature of the district heating network. Concerning the installed power generation capacity, in all simulation runs considerable CHP capacity is decommissioned, and new investments are considered, only in the form of modern and highly efficient conventional combined-cycle gas turbines. The model indicates no investments into the range of technologies highlighted by the Berlin Energy and Climate Protection Program, including CHP, wind power, PV, battery storage, and power-to-gas.

5.5.6 Development of heat capacity and generation

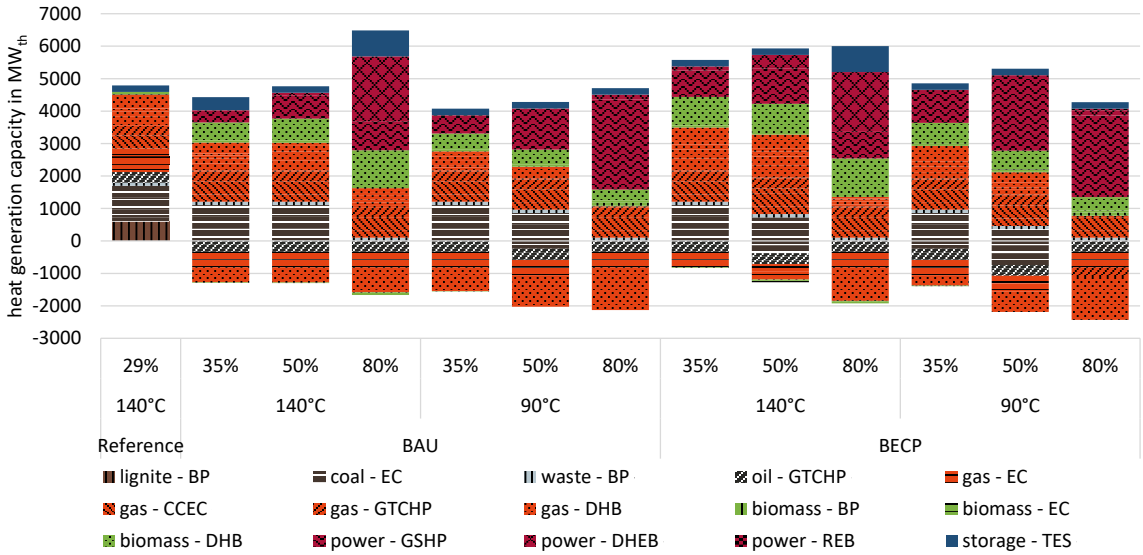
Figure 5.14 illustrates the development of thermal generation capacity and actual heat generation in Berlin's district heating network in the different simulation runs. The decommissioning of thermal capacity in the form of CHP plants in Figure 5.14a goes along

with the decommissions of CHP power generation capacity as depicted in 5.12a. As shown in Figure 5.14a, important decommissions are indicated for coal-fired CHP plants in simulation runs of the BECP scenario as well as the complete decommissioning of oil-fired CHP gas turbines and gas-fired extraction-condensation CHP plants in all simulation runs. The maximum and only investment into CHP observed in the BECP scenario occurs at 50% RES penetration and 140°C maximum supply temperature and amounts to 162 MW_{th} in the form of a CCEC capacity.

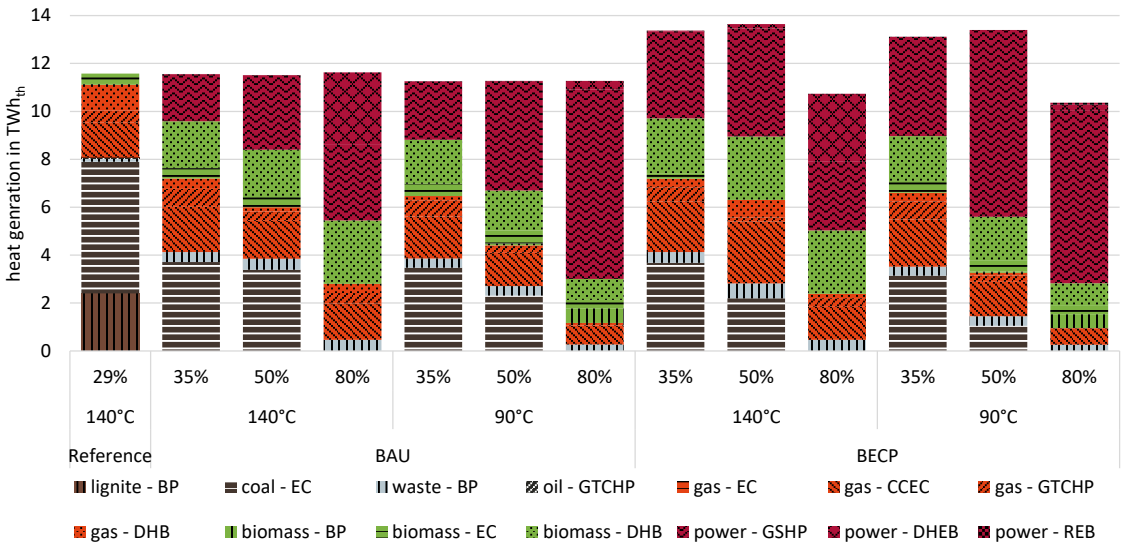
Significant changes in the capacity of gas-fired district heating boilers (DHBs) can also be noted. In total there is 961 MW_{th} of gas boiler capacity available in the Reference scenario and 1,321 MW_{th} in the BAU and BECP scenarios. No simulation runs indicate investments into additional gas-fired DHB capacity, instead, redundant capacity is decommissioned. In the BAU and BECP scenarios, two tendencies are observable. The more the maximum supply temperature of the district heating network is lowered, the more gas-fired DHB capacity is decommissioned. The same holds for the increase of RES penetration. The only exception, in which the entire capacity is maintained, occurs in the BECP scenario with a 140°C maximum supply temperature and at 35% and 50% RES penetration. In contrast, at 90°C maximum supply temperature the entire capacity is decommissioned at 80% RES penetration in both the BAU and BECP scenarios.

The decommissioning of the capacities is compensated mainly by investments into biomass-fueled district heating boilers, district heating ground source heat pumps, and district heating electrode boilers. Concerning biomass-fueled heat-only plants, the investments increase with higher RES penetration in the BAU and BECP scenarios when 140°C is maintained as the maximum supply temperature. Lowering it to 90°C requires substantially lower investments into biomass-fueled boilers with a decreasing tendency when RES penetration rises. This shift from gas to biomass-fueled district heating boilers can be explained by the increasing fuel and emission costs of gas compared to biomass. Moreover, these investments must be put into perspective with capacity investments into power-to-heat. The strongest thermal capacity expansions are shown by GSHPs, which increase along with RES penetration. This increase is significantly stronger at a low maximum supply temperature of 90°C in the district heating network. For instance, in the BAU scenario, the thermal capacity of GSHPs increases from 543 MW_{th} at 35% RES penetration to 2,768 MW_{th} at 80% RES penetration. In the BECP scenario, this development goes from 1,017 MW_{th} to 2,514 MW_{th}. The expansion of district heating electrode boilers (DHEBs) in the district heating network is especially pronounced when the maximum supply temperature stays elevated at 140°C. At 90°C the expansion of DHEBs is only 160 MW_{th} at 80% RES penetration in the BAU and BECP scenarios.

Investments into heat generation capacity closer to the site of consumption in the form of residential gas (RHBs) or electric boilers (REBs) either do not show up or are negligible. Consequently there are no production shifts closer to residences by means of these technologies, even though this could cut down on heat transmission losses and pumping work. The district heating network therefore maintains its importance in all of the simulation runs analyzed. Concerning the expansion of central thermal energy storage (TES), no clear tendency can be observed. Additional thermal storage for daily charging and discharg-



(a) Heat generation capacity.



(b) Heat generation.

Figure 5.14: Heat generation capacity and yearly generation.

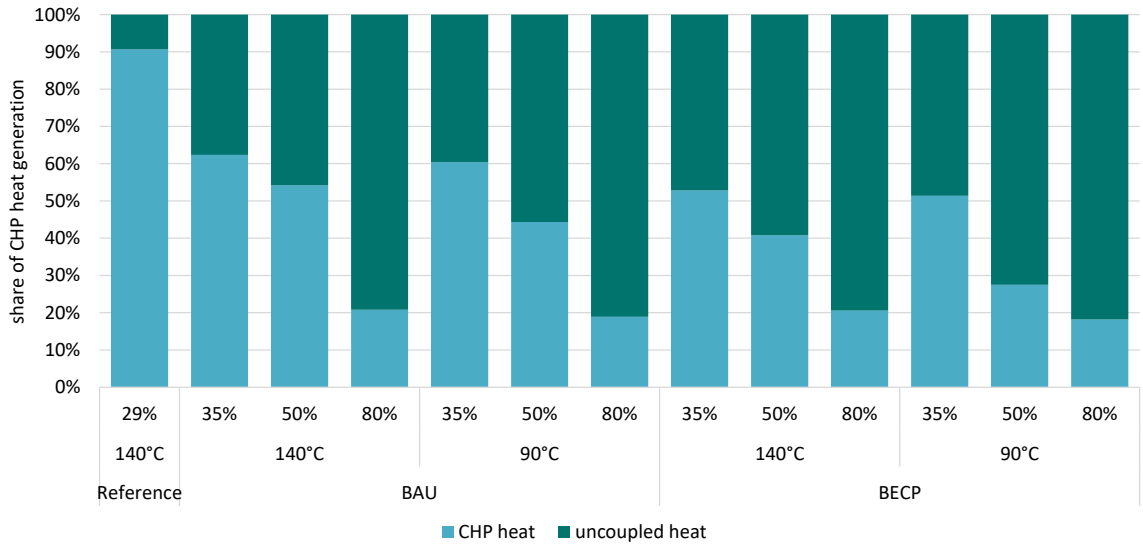


Figure 5.15: Development of the CHP heat share in the system.

ing activities appears at the 80% RES penetration level and when the maximum supply temperature stays at 140°C. Seasonal thermal storage is shown not to be an economically efficient investment. In this regard it must be noted that technologies like thermal boilers and power-to-heat, as well as heat accumulation in the piping, already have a substantial potential for flexibility. Furthermore, there are no investments into solar-thermal heat generation. In this model, this technology faces not only the constraint of the availability of solar radiation, but also the need for low temperatures at the point of heat injection into the district heating network. A favorable matching of these factors is therefore less likely and reduces its economic feasibility compared to alternative technologies.

Figure 5.14b presents the actual yearly heat generation by energy source and technology. From this figure it can be seen that the contributions by coal-fired CHP plants are significantly reduced at 35% and 50% RES penetration in not only the BECP scenario but even in the BAU scenario due to increasing emission costs. In both scenarios the effect is stronger when lowering the maximum supply temperature in the district heating network from 140°C to 90°C. The share of heating by gas changes significantly compared to the Reference scenario only when the maximum supply temperature is lowered; otherwise, it maintains its share in a similar way as in the mix of the Reference scenario. Biomass, on the other hand, expands its share in the mix up to the limits of its availability in Berlin. The strongest change is seen in the development of power-to-heat and in particular as a result of the contributions of the GSHPs. The share of power-to-heat rises with increasing RES penetration — at 80% RES penetration and 140°C maximum supply temperature it makes up more than half of Berlin's district heating supply in the BAU and BECP scenarios. At 90°C maximum supply temperature and 80% RES penetration, power-to-heat contributes nearly three quarters to the district heating supply. Consequently, lowering the temperature level in the district heating network clearly increases the utilization and

value of the GSHPs. Increasing contributions from biomass-fueled district heating boilers and power-to-heat is accompanied by a decline in the utilization of CHP technology in district heating. Figure 5.15 illustrates this further by showing the share of heat generation produced in CHP operation mode and in uncoupled production. In the Reference scenario, 90% of the yearly district heating production is generated in CHP mode operation. In all other simulation runs this share drops dramatically in the course of increasing RES penetration by lowering the district heating maximum supply temperature and by imposing CO_2 constraints as in the BECP scenario runs. The lowest share is shown in the BECP scenario with a 90°C DH network at 80% RES penetration, with about 18% heat generated in CHP operation mode.

5.6 Conclusion

The Berlin energy sector, which consists of both power and district heating generation, is currently based mainly on coal and gas for CHP generation and on electricity imports. In addition to national energy and climate protection policy measures, including the European emission trading system, the strong support of RES, the nuclear phase-out, and the national coal exit, the Berlin state government also pursues the Berlin Energy and Climate Protection Program. In order to achieve this program's targets, various transformations and new technologies for Berlin have been considered; these include lowering the maximum supply temperature in the district heating network as well as the deployment of modern gas-fueled CHP plants, vRES, batteries, power-to-heat, and power-to-gas. The techno-economic analysis presented in this paper comes to the conclusion that these plans can be supported only partly.

The district heating network operates continuously through the summer season (when only domestic hot water energy supply is required) in all simulations investigated here and is therefore maintained as envisaged by the Berlin Energy and Climate Protection Program. No investments into heat generation by means of residential fuel fired or electric boiler capacity at the site of consumption that would avoid transmission losses are considered. Lowering the temperature level in the district heating network decreases heat transmission losses only slightly. At the same time, pumping work can increase significantly, since it grows by the power of three of the increasing water mass flow rate. Yet this proves to be of little importance given pumping work's small share in the energy consumption of the entire Berlin energy system.

Unlike the considerations of the Berlin Energy and Climate Protection Program, this analysis shows no investments into vRES such as PV or wind power in Berlin or into local battery or power-to-gas capacities. Furthermore, no transformations in the form of a fuel switch from coal-fired CHP plants to gas-fired combined-cycle extraction-condensation CHP plants can be supported. The model shows no significant investments into CHP technology. In fact, according to this analysis, the role of CHP in the Berlin energy system declines substantially. The share of power and heat produced in cogeneration decreases with the increase of RES penetration in the national power system. This development is even more pronounced when the district heating maximum supply temperature is low-

ered. Instead of CHP, substantial investments into conventional combined-cycle gas turbine plants to substitute oil and coal-fired CHP plants are shown. Some decommissions of coal-fired CHP plants before the end of 2030 occur in the BAU scenario only when the district heating maximum supply temperature is lowered, since heat supply alternatives then become more likely. In some cases, the additional emission constraint in the BECP forces some earlier decommissioning of coal CHP capacity. This is also more pronounced when the district heating maximum supply temperature is lowered.

At future levels of RES penetration, a more economical heat supply in Berlin is provided by power-to-heat. Therefore, the energy system transformation goes along with important increases in the use of electricity for power-to-heat. With respect to the conventional yearly power demand of about 13 TWh_{el}, in the BECP scenario with a maximum supply temperature of 140°C for the district heating system, this new demand amounts to 0.8 TWh_{el}, 1.2 TWh_{el}, and 3.5 TWh_{el} at RES power system penetrations of 35%, 50%, and 80%, respectively. Lowering the district heating maximum supply temperature to 90°C reduces this demand to only 1.9 TWh_{el} at 80% RES penetration. This power-to-heat demand is mainly driven by large-scale ground source heat pumps accompanied to some degree by electric and biomass-fueled boilers in the district heating transmission network. Capacity investments into ground source heat pumps, along with their levels of heat generation, increase with higher RES penetrations and are significantly more pronounced when lowering the maximum supply temperature of the district heating system. No further investments into gas-fired heat boilers are shown. Instead, the more the maximum supply temperature is lowered and the higher the levels of RES penetration are, the more redundant gas-fueled heat-only plants are decommissioned. The shift from gas to biomass-fueled boilers can be explained by increasing fuel and emission costs for gas. The results indicate no clear need for the expansion of thermal energy storage tanks, nor any investments into solar-thermal heat generation. Consequently, CHP capacity can be substituted more economically by a mix of combined-cycle gas turbine plants, power imports, ground source heat pumps, and electric and biomass-fueled boilers. With such a mix, even the BAU scenario without emission constraints can undercut the Berlin 2050 emission target at 80% RES penetration.

Acknowledgments

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A Appendix to Chapter 2

A.1 Further formulations to model heat pumps

A.1.1 Formulation by Georges et al. (2017)

Equations (A.1a) to (A.1c) are based on Bolher et al. (1999). Equation (A.1d) determines the maximum power consumption for time slice t; equation (A.1e) computes the actual power consumption in part-load mode. Note that part-load mode does not relate to the maximum installed capacity here, but to what is maximally possible under the temperature circumstances in a particular time step. Specific parameters c, d, and f are based on manufacturer data and n indicates under nominal conditions. Georges et al. (2017) apply the same model for space heating and domestic hot water heat pumps, with different supply temperatures.

$$\overline{Q_t^{HP}} = (d_0 + d_1(T_t^a - T^{a,n}) + d_2(T_t^{sink} - T^{sink,n})) \cdot \dot{Q}^{HP,n} \tag{A.1a}$$

$$\Delta T_t = \frac{T_t^a}{T_t^{sink}} - \frac{T^{a,n}}{T^{sink,n}} \tag{A.1b}$$

$$\overline{COP}_t = \frac{COP^n}{c_0 + c_1 \Delta T_t + c_2 \Delta T_t^2} \tag{A.1c}$$

$$\overline{P_t} = \frac{\overline{Q_t^{HP}}}{\overline{COP_t}} \tag{A.1d}$$

$$P_t = \begin{cases} f_1 \frac{\dot{Q}_t^{HP}}{\overline{Q_t^{HP}}} \cdot \overline{P_t} & \text{, if } \frac{\dot{Q}_t^{HP}}{\overline{Q_t^{HP}}} \leq 0.3 \\ \left(f_2 \left(\frac{\dot{Q}_t^{HP}}{\overline{Q_t^{HP}}} - 0.3 \right) + f_3 \right) \cdot \overline{P}_t & \text{, if } 0.3 < \frac{\dot{Q}_t^{HP}}{\overline{Q_t^{HP}}} \leq 1 \end{cases} \tag{A.1e}$$

A.1.2 Formulation by Salpakari, Mikkola, and P. D. Lund (2016)

Using constraint (A.2a), Salpakari, Mikkola, and P. D. Lund (ibid.) allow supply of heat pumps to the district heating network only below supply temperatures of 90℃ (with M as sufficiently big number). Likewise, heat accumulation in the piping network is only allowed for a temperature increase up to 15 Kelvin within each period (A.2b).

$$P_t \leq \overline{P} = \begin{cases} M & \text{if } T_t^{sink} \leq 90[℃] \\ 0 & \text{if } T_t^{sink} > 90[℃] \end{cases} \tag{A.2a}$$

$$P_t \cdot COP^{average} \leq c \cdot \dot{m} \cdot \max\left(\min\left(T_t^{sink} + 15[K], 9[℃]\right) - T_t^{sink}, 0\right) \tag{A.2b}$$

where c and $\dot{m}$ represent the specific heat capacity of water and its mass flow respectively.

A.1.3 Formulation by Waite and Modi (2014)

Waite and Modi (ibid.) use data from heat pump manufactures for P^{HP} and $\dot{Q}^{HP}$ at different ambient temperatures to compute a temperature dependent COP (A.3a). They augment their formulation to include an auxiliary electric boiler, whose use is triggered when the ambient temperature falls below a pre-determined design temperature T^{design} according to equation (A.3b). $HD(T)$ renders the heating degree at temperature T and η^{EB} the electric boiler's efficiency.

$$COP(T^{source}) = \frac{\dot{Q}^{HP}(T^{source}) + \dot{Q}^{EB}(T^{source})}{P^{HP}(T^{source}) + P^{EB}(T^{source})} \tag{A.3a}$$

$$\dot{Q}^{EB}(T) = \begin{cases} 0 & \text{, if } T^{source} \geq T^{design} \\ \frac{HD(T^{source})}{HD(T^{design})} \cdot \dot{Q}^{HP}(T^{design}) - \dot{Q}^{HP}(T^{source}) & \text{, if } T^{source} < T^{design} \end{cases} \tag{A.3b}$$

$$P^{EB}(T^{source}) = \eta^{EB} \cdot \dot{Q}^{EB}(T^{source}) \tag{A.3c}$$

B Appendix to Chapter 3

B.1 Nomenclature

Sets

$chp \in \mathcal{CHP}$	combined power and heat generation technologies $\mathcal{CHP} \subseteq \mathcal{I}$
$chp_{bp} \in \mathcal{CHP}^{\mathcal{BP}}$	back-pressure CHP technologies $\mathcal{CHP}^{\mathcal{BP}} \subseteq \mathcal{CHP}$
$chp_{ec} \in \mathcal{CHP}^{\mathcal{EC}}$	extraction-condensation CHP technologies $\mathcal{CHP}^{\mathcal{EC}} \subseteq \mathcal{CHP}$
$cp \in \mathcal{CP}$	conventional power generation technologies $\mathcal{CP} \subseteq \mathcal{I}$
$f \in \mathcal{F}$	fuels
$h \in \mathcal{H}$	only heat generation technologies $\mathcal{H} \subseteq \mathcal{I}$
$i \in \mathcal{I}$	technologies
$p \in \mathcal{P}$	power generation technologies $\mathcal{P} \subseteq \mathcal{I}$
$p2g \in \mathcal{P}2\mathcal{G}$	power-to-gas technologies $\mathcal{P}2\mathcal{G} \subseteq \mathcal{I}$
$p2h \in \mathcal{P}2\mathcal{H}$	power-to-heat technologies $\mathcal{P}2\mathcal{H} \subseteq \mathcal{I}$
$s \in \mathcal{S}$	storage technologies $\mathcal{S} \subseteq \mathcal{I}$
$vres \in v\mathcal{RES}$	vRES technologies $v\mathcal{RES} \subseteq \mathcal{I}$

Parameters

$a_{i,f}$	annuity factor	[-]
$\beta_{i,f}$	power loss coefficient	[-]
$c^{fom}_{i,f}$	specific fixed O&M	[€/MW]
$cf_{i,f,t}$	capacity factor for vRES technologies	[-]
$c^{inv}_{i,f}$	specific investment cost	[€/MW]
$c^{invST}_{i,f}$	specific investment cost for storage volume	[€/MWh]
$c^{var}_{i,f}$	variable cost	[€/MWh]
$c^{var\ O\&M}_{i,f}$	variable O&M	[€/MWh]
$c^{ramp}_{i,f}$	ramping cost	[€/MW]
$elt_{i,f}$	economic lifetime	[years]
$\eta_{i,f}$	total fuel efficiency	[-]
$\eta^{cm}_{i,f}$	condensation mode efficiency	[-]
fp_f	fuel price	[€/MWh]
ir	interest rate	[-]
p_t	conventional power load	[MW]
q_t	heat load	[MW]
$r^{dn}_{i,f}$	ramping down velocity	[-]
$r^{up}_{i,f}$	ramping up velocity	[-]
$\sigma_{i,f}$	power-over-heat-ratio	[-]
x	power share	[-]

Positive variables

$C_{i,f,t}^{vRES}$	vRES curtailment	[MW]
D_t^{P2G}	power load caused by power-to-gas	[MW]
D_t^{P2H}	power load caused by power-to-heat	[MW]
$FC_{i,f,t}$	fuel consumption	[MW]
$FO\&MC$	fixed operation and maintenance cost	[€]
$\overline{G}_{i,f}$	maximum power capacity	[MW]
$G_{i,f,t}$	power generation	[MW]
$G_{i,f}^{dn}$	ramping down	[MW]
$G_{i,f}^{up}$	ramping up	[MW]
HS_t^C	heat storage charging	[MW]
HS_t^D	heat storage discharging	[MW]
HS_t^L	heat storage charge level	[MWh]
IC	investment cost	[€]
OC	operating cost	[€]
PS_t^C	power storage charging	[MW]
PS_t^D	power storage discharging	[MW]
PS_t^L	power storage charge level	[MWh]
$\overline{Q}_{i,f}$	maximum heating capacity	[MW]
$Q_{i,f,t}$	heat generation	[MW]
$\overline{S}_{i,f}$	maximum storage capacity	[MWh]
SG_t^C	synthetic gas charging by P2G	[MW]
SG_t^D	synthetic gas discharging by P2G	[MW]
SG_t^L	synthetic gas storage level by P2G	[MWh]
TC	total cost	[€]

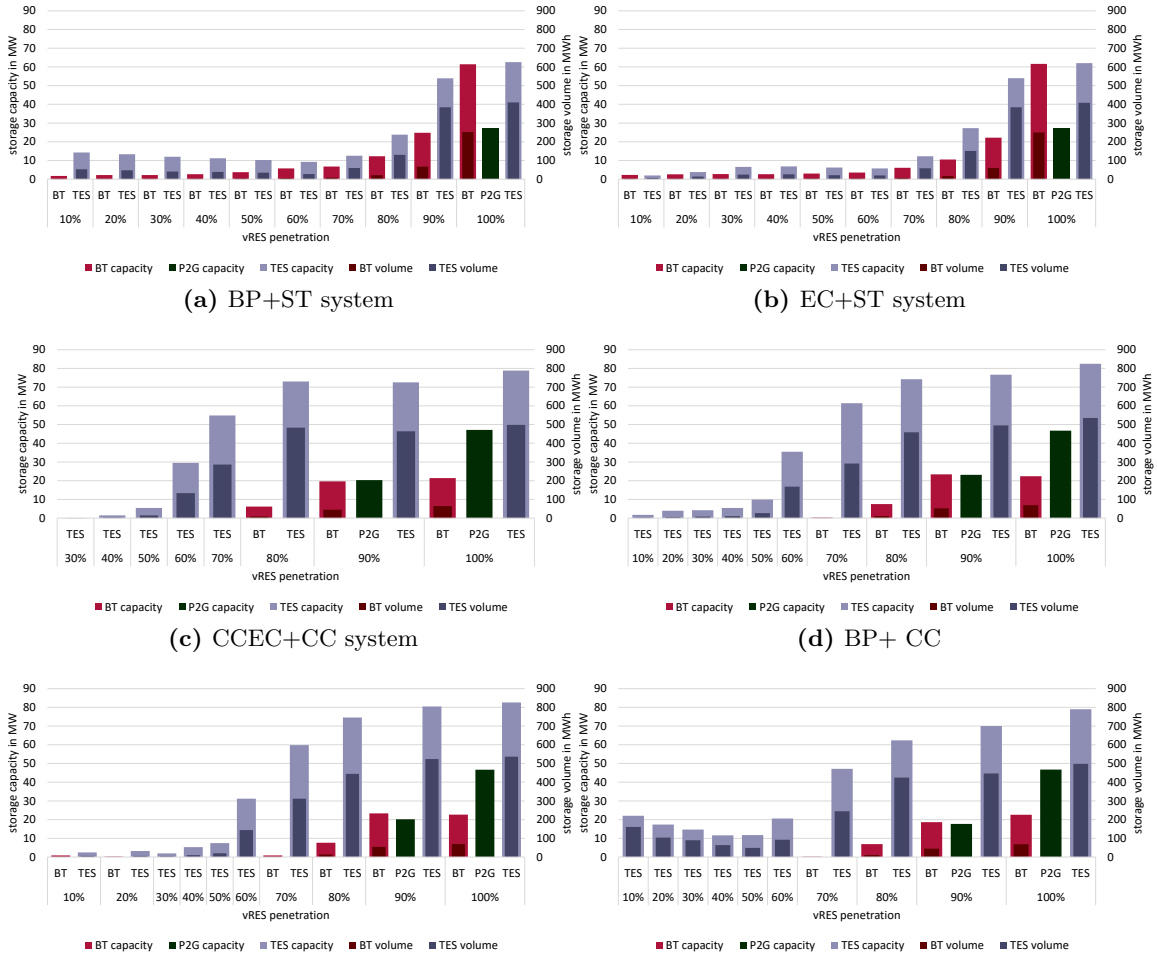
B.2 Technology data

Table B.2: Technology data.

Technology	Fuel	Investment cost €/kW	Investment cost storage €/kWh	fixed O&M cost €/kW	variable O&M cost €/MWh	Ramping cost €/MW	Economic lifetime years	Efficiency (cm*) %	Ramp rate %/h
ST	coal	1,800		50	6	50	40	40	30
BP	coal	1,980		55	6.6	50	40	90	30
EC	coal	2,160		55	6.6	50	40	75 (40)	30
GT	gas	556		15	2	20	40	35	100
GTCHP	gas	715		16.5	2	20	30	85 (35)	100
CC	gas	800		20	3	20	30	52	100
CCEC	gas	960		22	3.3	20	30	75 (52)	100
DHB	gas	219		11			30	105	
DHEB	power	170		1.7			20	98	
GSHP	power	1,500		5.5	2		20	300	
TES	storage	67	2.7				30	90	
BT	storage	150	625	3.5			20	90	
P2G	storage	1,869		93	1		20	70	

* Condensation mode (CM) efficiency.
Source: Gerbaulet and Lorenz (2017) and own estimations.

B.3 Storage investments



(a) BP+ST system

(b) EC+ST system

(c) CCEC+CC system

(d) BP+ CC

(e) EC+CC system

(f) mix system

Figure B.1: Development of investments into thermal energy storage (TES), batteries (BTs), and power-to-gas (P2G) over increasing vRES penetration.

C Appendix to Chapter 4

C.1 Nomenclature

Sets

$f \in F$	fuels
$i \in I$	technologies
$h \in H$	subset of I for heat generating technologies $H \subseteq I$
$h^{DH} \in H^{DH}$	DH generation technologies $H^{DH} \subseteq H$
$h^{IH} \in H^{IH}$	IH generation technologies $H^{IH} \subseteq H$
$hs \in HS$	heat storage technologies $HS \subseteq H$
$hz \in HZ$	heat zones
$cgu \in CGU$	cogeneration unit technologies $CGU \subseteq H^{IH}$
$chp \in CHP$	various CHP technologies $CHP \subseteq H^{DH}$
$chp^{bp} \in CHP^{BP}$	back-pressure CHP $CHP^{BP} \subseteq CHP$
$chp^{pl} \in CHP^{PL}$	CHP technologies with power loss $CHP^{PL} \subseteq CHP$
$oh \in OH$	heat-only generation technologies $OH \subseteq H$
$f2h \in F2H$	various fuel-to-heat technologies $F2H \subseteq H$
$f2h^{DH} \in F2H^{DH}$	various DH fuel-to-heat technologies $F2H^{DH} \subseteq F2H$
$f2h^{IH} \in F2H^{IH}$	various IH fuel-to-heat technologies $F2H^{IH} \subseteq F2H$
$oh^{IH} \in OH^{IH}$	heat-only generation technologies for IH $OH^{IH} = OH \cap H^{IH}$
$oh^{DH} \in OH^{DH}$	heat-only generation technologies for DH $OH^{DH} = OH \cap H^{DH}$
$p \in P$	plant blocks
$s2h \in S2H$	subset of OH^{IH} for IH solar-to-heat technology
$t \in T$	hours $T = \{1...8760\}$
$t_h \in T$	heating season hours $T_h = \{1...2904, 5856...8760\}$
$y \in Y$	years $Y = \{2015, 2020, 2030, 2040, 2050\}$
$yy \in YY$	vintage years $YY = \{2020, 2030, 2040, 2050\} \subseteq Y$

Parameters

ava_i	availability of capacity	[-]
$ava^{RES}_{i,t,y}$	RES availability factor	[-]
$\beta_{i,yy}$	power loss gradient for extraction-condensation CHP	[-]
$cc_{i,f}$	carbon content	[t_{CO_2}/MWh]
$c^{fix}_{i,y}$	fix costs	[€/MW]

$c_{i,y}^{inv}$	investment costs	[€/MW]
$c_{i,y}^{ram}$	ramping costs	[€/MW]
$cs_{i,y}^{CHP}$	capacity share of each existing CHP technology	[-]
$cs_{i,y}^{IH}$	capacity share of each existing F2H and CU technology	[-]
$c_{i,y,yy}^{var}$	variable costs	[€/MWh]
df_y	discount factor	[-]
el_y	emission limit	[t]
$\epsilon_{i,t,y,yy}^{AS}$	ambient temperature depended COP for ASHPs	[-]
$\epsilon_{t,y,yy}^{Carnot}$	temperature depended Carnot-COP for heat pumps	[-]
$\epsilon_{i,yy}^{GS}$	non ambient temperature depending COP for GSHPs	[-]
$\epsilon_{i,t,y,yy}$	temperature depending COP for heat pumps	[-]
$\eta_{i,yy}$	conversion efficiency	[-]
$\eta_{i,yy}^{CM}$	conversion efficiency in condensation mode	[-]
$\overline{f_y^{biomass}}$	maximum yearly biomass fuel availability	[MWh]
$\overline{g}_{p,i,y}$	maximum power generation of existing capacity	[MW_{el}]
$\overline{q_{p,i,y,hz}^{DH}}$	maximum DH generation of existing capacity	[MW_{th}]
$\overline{q_{i,y}^{IH}}$	maximum IH generation of existing capacity	[MW_{th}]
hdh_t	heating degree hours	[h]
$hpcs$	heat pump capacity share for electric boiler backup	[-]
$htlf_{hz}$	heat transmission loss factor	[-]
$\omega_{i,yy}$	quality grade of heat pumps	[-]
p_t^{DHW}	domestic hot water heating profile	[-]
$p_{y,t}^{IH}$	IH demand profile	[-]
$q_{t,y}$	power demand	[MW_{el}]
$q_{t,y,hz}^{DH}$	DH energy demand	[MW_{th}]
$\overline{q_{y,hz}^{DH,SH}}$	total DH space heating demand	[MWh_{th}]
$\overline{q_{y,hz}^{DH,DHW}}$	total DH domestic hot water heating demand	[MWh_{th}]
$q_{t,y}^{IH}$	IH energy demand	[MW_{th}]
$\overline{q_y^{IH,SH}}$	total IH space heating demand	[MWh_{th}]
$\overline{q_y^{IH,DHW}}$	total IH domestic hot water heating demand	[MWh_{th}]
$\sigma_{i,yy}$	power-to-heat ratio for CHP and cogeneration	[-]
$T_{t,y}^a$	ambient temperature	[K]
tlt	technical lifetime	[years]
T_{yy}^s	supply temperature	[K]
$\vartheta_{t,y}^a$	ambient temperature	[°C]
ϑ_{yy}^s	supply temperature	[°C]

Variables

$F_{i,t,y,yy}$	fuel consumption	[MW]
$\overline{G}_{i,yy}$	maximum power generation of newly installed capacity	[MW_{el}]
$G_{i,t,y,yy}$	power generation	[MW_{el}]

$G^{dn}_{i,t,y}$	ramping down	[MW_{el}]
$G^{up}_{i,t,y}$	ramping up	[MW_{el}]
$\overline{HS}_{i,yy}$	maximum heat storage energy volume	[MWh_{th}]
$HS^{C}_{i,t,y}$	heat storage charging	[MW_{th}]
$HS^{D}_{i,t,y}$	heat storage discharging	[MW_{th}]
$HS^{L}_{t,y}$	heat storage charge level	[MWh_{th}]
IC^{H}	investment costs of heat supply	[€]
$L^{IH}_{i,y,yy}$	IH production level	[MW_{th}]
OC^{H}	operation costs of heat supply	[€]
$\overline{Q^{DH}_{i,yy,hz}}$	maximum DH generation of newly installed capacity	[MW_{th}]
$O\&MC^{H}$	fixed operation and maintenance costs of heat supply	[€]
$Q^{DH}_{i,t,y,yy,hz}$	DH heat generation	[MW_{th}]
$\overline{Q^{IH}_{i,yy}}$	maximum IH generation of newly installed capacity	[MW_{th}]
$Q^{IH}_{i,t,y,yy}$	IH heat generation	[MW_{th}]
$Q^{P2H}_{t,y}$	aggregated endogenous power-to-heat demand	[MW_{el}]
TC	total system costs	[€]

C.2 Original dynELMOD technology overview

Table C.2: Original dynELMOD technology overview.

	Technology	Overnight cost €/kW		fixed O&M €/kW		variable O&M €/MWh		Efficiency %		Technical lifetime years		Economic lifetime years		Storage capacity €/kWh	
		2015	2050	2015	2050	2015	2050	2015	2050	2015	2050	2015	2050	2015	2050
Fossil	Nuclear	6,000	6,000	100	100	9	9	0.33	0.34	50	50	30	30		
	Lignite	1,800	1,800	60	60	7	7	0.43	0.47	40	40	30	30		
	Coal	1,800	1,800	50	50	6	6	0.46	0.47	40	40	30	30		
	CC	800	800	20	20	3	3	0.60	0.62	40	40	30	30		
	GT	550	550	15	15	2	2	0.39	0.40	40	40	30	30		
	GasSteam	550	550	15	15	3	3	0.41	0.42	40	40	30	30		
	CCOT	800	800	25	25	4	4	0.60	0.62	40	40	30	30		
	OCOT	400	400	6	6	3	3	0.39	0.40	40	40	30	30		
	OilSteam	400	400	6	6	3	3	0.41	0.42	40	40	30	30		
	Waste	2,424	1,951	100	100	7	7	1.00	1.00	50	50	30	30		
Renewable	Biomass	2,400	2,400	100	100	7	7	0.38	0.38	40	40	30	30		
	Reservoir	2,000	2,000	20	20	0	0	0.75	0.75	100	100	30	30		
	ROR	3,000	3,000	60	60	0	0	1.00	1.00	100	100	30	30		
	WPon	1,063	851	35	35	0	0	1.00	1.00	25	25	20	20		
	WPoff	3,500	1,592	35	35	0	0	1.00	1.00	25	25	20	20		
	PV	998	230	25	25	0	0	1.00	1.00	25	25	20	20		
	CSP	5,300	3,200	30	30	0	0	1.00	1.00	30	30	30	30		
	Tidal	4,608	2,600	150	150	0	0	1.00	1.00	50	50	30	30		
	Geothermal	3,982	2,740	80	80	0	0	1.00	1.00	50	50	30	30		
CCTS	Lignite CCTS	3,950	3,600	90	90	8	8	0.30	0.33	50	50	30	30		
	Coal CCTS	3,550	3,200	80	80	8	8	0.31	0.34	50	50	30	30		
	CC CCTS	1,670	1,460	40	40	4	4	0.49	0.52	50	50	30	30		
	GT CCTS	1,384	1,280	30	30	4	4	0.34	0.34	50	50	30	30		
	Biomass CCTS	5,630	5,140	120	120	8	8	0.26	0.27	50	50	30	30		
Storage	PSP	2,000	2,000	20	20	0	0	0.75	0.75	100	100	30	30	10	10
	BT	153	35	3	1	0	0	0.88	0.92	8	13	10	10	625	100
	power-to-gas	1,850	800	37	16	1	1	0.37	0.37	20	20	20	20	0	0
	DSM01	745	745	0	0	0	0	1.00	1.00	10	10	10	10	1	1
	DSM04	835	835	0	0	0	0	1.00	1.00	10	10	10	10	1	1
	DSM12	30	30	0	0	0	0	1.00	1.00	10	10	10	10	1	1
	DSMLT	180	40	0	0	0	0	0.80	0.80	10	10	10	10	0	0

Source: Gerbaulet and Lorenz (2017) with data compiled from data by Schröder et al. (2013) and other sources.

D Appendix to Chapter 5

D.1 Nomenclature

Sets

$f \in \mathcal{F}$	fuel
$i \in \mathcal{I}$	technology
$i_p \in \mathcal{IP}$	power generating technology $\mathcal{IP} \subseteq \mathcal{I}$
$i_{p2h} \in \mathcal{IP2H}$	power-to-heat technology $\mathcal{IP2H} \subseteq \mathcal{I}$
$i_{ps} \in \mathcal{PS}$	power storage technology $\mathcal{PS} \subseteq \mathcal{I}$
$i_{cp} \in \mathcal{CP}$	conventional plant technology $\mathcal{CP} \subseteq \mathcal{I}$
$i_{chp} \in \mathcal{CHP}$	CHP technology $\mathcal{CHP} \subseteq \mathcal{I}$
$i_{chp_{bp}} \in \mathcal{CHP}_{\mathcal{BP}}$	back-pressure CHP technology $\mathcal{CHP}_{\mathcal{BP}} \subseteq \mathcal{CHP}$
$i_{chp_{ec}} \in \mathcal{CHP}_{\mathcal{EC}}$	extraction-condensation CHP technology $\mathcal{CHP}_{\mathcal{EC}} \subseteq \mathcal{CHP}$
$i_{hp} \in \mathcal{HP}$	heat-only plant technology $\mathcal{HP} \subseteq \mathcal{I}$
$n \in \mathcal{N}$	heating network node
$n_R \in \mathcal{NR}$	residential heating network node $\mathcal{NR} \subseteq \mathcal{N}$
$n_T \in \mathcal{NT}$	transmission heating network node $\mathcal{NT} \subseteq \mathcal{N}$
$p \in \mathcal{P}$	plant block
$p_B \in \mathcal{PB}$	plant block located in Berlin $\mathcal{PB} \subseteq \mathcal{P}$
$s2h \in \mathcal{S2H}$	solar-thermal-to-heat units
$t \in \mathcal{T}$	time step
$t_h \in \mathcal{TH}$	time step within heating season $\mathcal{TH} \subseteq \mathcal{T}$
$tes \in \mathcal{TES}$	thermal energy storage units

Parameters

α	ratio of pumping work heat recovery	[-]
$\beta_{p,i,f}$	power loss ratio in CHP plants	[-]
γ_t	S2H radiation availability factor	[0;1]
$c^{fO\&M}_{p,i,f}$	marginal fixed operating and maintenance cost	[€/MW]
$c^{inv}_{p,i,f}$	marginal investment cost	[€/MW]
$c^{inv,PS}_{p,i,f}$	marginal investment cost for power storage energy volume	[€/$\mathrm{MWh_{el}}$]
$c^{ramp}_{p,i,f}$	marginal ramping cost	[€/$\mathrm{MW_{el}}$]
$\overline{c^{S2H}_{s2h}}$	potential maximum heat generation capacity of S2H	[$\mathrm{MW_{th}}$]
$\overline{c^{TES}_{tes}}$	potential charging/discharging capacity of TES	[$\mathrm{MW_{th}}$]
c^{TL}	transmission loss factor	[$\mathrm{MW_{th}}$/K]
$c^{var}_{p,i,f}$	marginal variable cost	[€/MWh]
c_w	specific heat capacity of water	[MWh/(t K)]
cs^{TES}	cost structure for TES	[-]
$cf^{vRES}_{i,f,t}$	capacity factor of vRES capacity	[-]
d^{DH}	total yearly district heating energy demand	[$\mathrm{MWh_{th}}$]
d^{DHW}_t	domestic hot water heating demand	[$\mathrm{MW_{th}}$]

d_t^P	conventional power demand*	[MW_{el}]
d_t^{PW}	potential pumping work power demand	[MW_{el}]
d_t^{SH}	space heating demand	[MW_{th}]
d_t^Q	heat demand	[MW_{th}]
$\underline{\Delta\vartheta}$	minimum temperature spread	[K]
$\eta_{p,i,f}$	efficiency	[-]
$\eta_{p,i,f}^{cm}$	efficiency in condensation mode for extraction-condensation CHP	[-]
η^{PW}	pumping work efficiency	[-]
ϵ_t	COP for ground source heat pumps	[-]
$\overline{f^{bio}}$	maximum biomass fuel consumption	[MWh]
$\overline{g}_{p,i,f}$	existing maximum power generation capacity	[MW_{el}]
hdh_t	heating degree hours	[-]
λ	adjustment parameter	[-]
M	big number	[-]
m_t^R	residential water mass flow	[t/h]
m_t^T	transmission water mass flow	[t/h]
NR	network resistance	[1/(t m)]
$\overline{q}_{p,i,f}$	existing maximum heat generation capacity	[MW_{th}]
$\underline{r_i^{dn}}$	ramping down rate	[-]
$\overline{r_i^{up}}$	ramping up rate	[-]
ρ	density of water	[t/m³]
s^{RES}	share of renewable energy sources in the system	[-]
$\sigma_{p,i,f}$	power over heat ratio in CHP plants	[-]
$\underline{\vartheta_t^a}$	ambient temperature	[°C]
$\overline{\vartheta_{s2h,i}^{S2H}}$	maximum system temperature of S2H unit	[°C]
$\overline{\vartheta_{'n1','n2'}^{T}}$	maximum central DH station output temperature	[°C]
$\overline{\vartheta^{TES}}$	maximum storage temperature of TES	[°C]
$\overline{\vartheta^{TS}}$	maximum transmission supply temperature	[°C]
$\underline{\vartheta^{TR}}$	minimum transmission return temperature	[°C]
$\underline{\vartheta^{TS}}$	minimum transmission supply temperature	[°C]
$\overline{v_{tes}^{TES}}$	potential charging volume of TES	[m³]
Variables		
$FO\&MC$	fixed operating and maintenance cost	[€]
IC	investment cost	[€]
IMC	import cost	[€]
OC	operating cost	[€]
TC	total cost	[€]
Positive variables		
AV_t^+	artificial positive variable	
$C_{p,i,f,t}^{vRES}$	vRES curtailment	[MW_{el}]
C_{s2h}^{S2H}	realized maximum heat generation capacity of S2H	[MW_{th}]
C_{tes}^{TES}	realized charging/discharging capacity of TES	[MW_{th}]
$COPEX$	cost per unit of exergy production	[€/MWh_{ex}]

*high index B: only Berlin, -B: Germany w/o Berlin

D_t^{P2G}	power-to-gas caused power demand*	[MW_{el}]
D_t^{P2H}	power-to-heat caused power demand	[MW_{el}]
D_t^{PW}	realized pumping work power demand	[MW_{el}]
$FC_{p,i,f,t}$	fuel consumption	[MW]
$G_{p,i,f,t}$	power generation*	[MW_{el}]
$G_{p,i,f,t}^{dn}$	ramping down power generation	[MW_{el}]
$G_{p,i,f,t}^{up}$	ramping up power generation	[MW_{el}]
$\overline{G}_{p,i,f}$	maximum power generation capacity	[MW_{el}]
$H_{n,n,t}$	enthalpy stream	[MW_{th}]
$\overline{TES}_{tes}$	thermal energy storage volume	[MWh_{th}]
$\overline{PS}_{p,i,f}$	maximum power storage volume	[MWh_{el}]
$PS_{p,i,f,t}^{C}$	power storage charging*	[MW_{el}]
$PS_{p,i,f,t}^{D}$	power storage discharging*	[MW_{el}]
$PS_{p,i,f,t}^{L}$	power storage charging level	[MWh_{el}]
$Q_{p,i,f,t}$	heat generation	[MW_{th}]
$\overline{Q}_{p,i,f}$	maximum heat generation capacity	[MW_{th}]
$Q_{s2h,t}^{S2H}$	heat generation in S2H	[MW_{th}]
Q_t^{TLR}	heat transmission loss during return	[MW_{th}]
Q_t^{TLS}	heat transmission loss during supply	[MW_{th}]
$SG_{p,i,f,t}^{D}$	synthetic gas demand	[MW]
SG_t^{L}	synthetic gas storage level	[MWh]
$T_{nn,n,t}^{R}$	residential stream temperature	[°C]
$T_{nn,n,t}^{T}$	transmission stream temperature	[°C]
TEx^{H}	total exergy production in the form of heat	[MWh_{th}]
TEx^{P}	total exergy production in the form of electricity	[MWh_{el}]
$\overline{V_{tes}^{TES}}$	realized charging volume of TES	[m^3]
Binary variables		
$X_{p,i,f}^{D}$	decommissioning variable	
X_{s2h}^{S2H}	investment decision in S2H capacity	
$X_{s2h,t}^{S2H,C}$	S2H heat generation decision variable	
X_t^{T}	hourly heat transmission decision variable	
X_{tes}^{TES}	investment decision in TES capacity	
$X_{tes,t}^{TES,C}$	TES charging decision variable	

D.2 Further model formulations

D.2.1 Formulations for the joint power and district heating system

Fixed O&M costs arise for each unit of existing or newly installed capacity for power generation, $\overline{G}_{p,i,f}$, or heat generation, $\overline{Q}_{p,i,f}$, (D.1). TES tanks impose fixed O&M costs

*high index B: only Berlin, -B: Germany w/o Berlin

for their storage volume, $\overline{V_{tes}^{TES}}$, and their charging/discharging capacity, $\overline{C_{tes}^{TES}}$.

$$\begin{aligned} FO\&MC = \sum_{p}\sum_{f}\Bigg(&\sum_{i_p \cup i_{p2h} \cup i_{ps}} \left(c_{p,i,f}^{fO\&M} \cdot \overline{G}_{p,i,f}\right) + \sum_{i_{hp}} \left(c_{p,i,f}^{fO\&M} \cdot \overline{Q}_{p,i,f}\right) \\ &+ c_{p,i|i\hat{=}\mathrm{TES},f}^{fO\&M} \cdot \left(cs^{TES} \cdot \sum_{tes} \overline{V_{tes}^{TES}} + \left(1 - cs^{TES}\right) \cdot \sum_{tes} \overline{C_{tes}^{TES}}\right)\Bigg) \end{aligned} \tag{D.1}$$

Investment costs come with each unit of newly installed power or heat capacity, and for TES tanks, are imposed independently for storage volume and charging/discharging capacity, (D.2).

$$\begin{aligned} IC = \sum_{p}\sum_{f}\Bigg(&\sum_{i_p \cup i_{p2h} \cup i_{ps}} \left(c_{p,i,f}^{inv} \cdot \overline{G}_{p,i,f}\right) + \sum_{i_{hp}} \left(c_{p,i,f}^{inv} \cdot \overline{Q}_{p,i,f}\right) \\ &+ c_{p,i|i\hat{=}\mathrm{TES},f}^{inv} \cdot \left(cs^{TES} \cdot \sum_{tes} \overline{V_{tes}^{TES}} + \left(1 - cs^{TES}\right) \cdot \sum_{tes} \overline{C_{tes}^{TES}}\right)\Bigg) \\ &+ c_{p,i,f}^{inv,PS} \cdot \overline{PS}_{p,i,f} \end{aligned} \tag{D.2}$$

D.2.2 Formulations for the power system

Ramping constraints

Load changes up and down are determined by equation (D.3a). Power generation based on steam cycle processes face additional constraints through maximum ramp rates, $\overline{r_i^{up}}$ and $\overline{r_i^{dn}}$, in constraints (D.3b) and (D.3c), respectively.

$$G_{p,i,f,t} - G_{p,i,f,t-1} = G_{p,i,f,t}^{up} - G_{p,i,f,t}^{dn} \qquad \forall\ p,i,f,t \tag{D.3a}$$

$$G_{p,i,f,t}^{up} \leq \overline{r_i^{up}} \cdot \overline{G}_{p,i,f} \qquad \forall\ p,i,f,t \tag{D.3b}$$

$$G_{p,i,f,t}^{dn} \leq \overline{r_i^{dn}} \cdot \overline{G}_{p,i,f} \qquad \forall\ p,i,f,t \tag{D.3c}$$

Power storage constraints

There are various types of storage in the German power system, including pumped hydro power and batteries. Only investments into battery storage can occur in the Berlin power system. Equation (D.4a) models the state of charge for each power storage technology. Constraints (D.4b), (D.4c), and (D.4d) limit the storable energy volume and the charging

and discharging capacities, respectively.

$$PS^L_{p,i,f,t} = PS^L_{p,i,f,t-1} + \left(\eta_{p,i,f} \cdot PS^C_{p,i,f,t}\right) - PS^D_{p,i,f,t} \qquad \forall\, p, i_{ps}, f, t \qquad \text{(D.4a)}$$

$$PS^L_{p,i,f,t} \leq \overline{PS}_{p,i,f} \qquad \forall\, p, i_{ps}, f, t \qquad \text{(D.4b)}$$

$$PS^C_{p,i,f,t} \leq \overline{G}_{p,i,f} \qquad \forall\, p, i_{ps}, f, t \qquad \text{(D.4c)}$$

$$PS^D_{p,i,f,t} \leq \overline{G}_{p,i,f} \qquad \forall\, p, i_{ps}, f, t \qquad \text{(D.4d)}$$

Power-to-gas storage constraints

When operating power-to-gas plants, the state of charge of synthetic gas is increased by using power for power-to-gas, D^{P2G}_t, and decreased through the use of synthetic gas for various gas-fired technologies, $SG^D_{p,i,f,t}$, in equation (D.5a). The hourly charging capacity is limited by the available power-to-gas capacity according to constraint (D.5b). Unlike the charging level of power storage, the charging level for synthetic gas, SG^L_t, is practically unbounded.

$$SG^L_t = SG^L_{t-1} + \eta_{p,i,f} \cdot D^{P2G}_t - \sum_p \sum_i \sum_f SG^D_{p,i,f,t} \qquad \forall\, t \qquad \text{(D.5a)}$$

$$D^{P2G}_t \leq \overline{G}_{p,i,f} \qquad \forall\, t \qquad \text{(D.5b)}$$

D.2.3 Formulations for the district heating system

Thermal energy storage

Apart from heat storage by means of heat accumulation in the piping of the district heating network, further possibilities of thermal energy storage include extra TES tanks, such as the hot water tank at the site of the Berlin CHP plant Reuter West. At atmospheric pressure, this tank can contain up to 60,000 m^3 of water. This enables it to store up to 2,500 $\mathrm{MWh_{th}}$ of heat energy, which can be completely released within 12.5 hours, amounting to a maximum discharging capacity of 200 $\mathrm{MW_{th}}$.

The charging and discharging capacity is also subject to current temperature levels in the piping. Equation (D.6a) formulates the state of charge of a TES tank. According to this equation, the current charge level is determined by charging, $TES^C_{tes,t}$, discharging, $TES^D_{tes,t}$, the former charge level, and the stand-by loss, $\eta_{p,\text{'}TES\text{'},f} \cdot \mathrm{TES}^L_{tes,t-1}$. The charge level is limited according to constraint (D.6b) in conjunction with relation (D.6j) by the water storage volume, $\overline{V^{TES}_{tes}}$, and by the temperature spread between the maximum TES temperature, $\overline{\vartheta^{TES}}$, and the minimum return flow temperature in the network, $\underline{\vartheta^{TR}}$. The maximum TES temperature is assumed to be always 95°C, whereas the minimum return flow temperature can vary; for instance, it is assumed to be 70°C in the Reference scenario. The charging capacity, $TES^C_{tes,t}$, is constrained by (D.6c) in conjunction with relation (D.6k), whereby the binary investment decision variable X^{TES}_{tes} determines the availability of the maximum charging capacity, $\overline{c^{TES}_{tes}}$. When such a charging capacity is available, constraint (D.6d) and (D.6e) control its operation. According to these constraints, the

hourly binary operation decision variable $X_{tes,t}^{TES,C}$ can become 1 only if the heat energy flow $H_{`n1',`n2',t}$ has a higher temperature than the TES tank, which is assumed to always store heat at $\overline{\vartheta^{TES}} = 95$°C. If this is the case, constraint (D.6f) determines the extent to which the maximum charging capacity $\overline{c_{tes}^{TES}}$ can be exploited. For instance, if $T_{`n1',`n2',t}^{T}$ equals $\overline{\vartheta_{`n1',`n2'}^{DHS}} = 140$°C, then the full capacity is available. If however $T_{`n1',`n2',t}^{T}$ is equal to or less than $\overline{\vartheta^{TES}} = 95$°C, then the TES tank cannot be charged at all. The same mechanisms are employed for the discharging of TES in constraints (D.6g), (D.6h), and (D.6i). According to these, discharging is only enabled when the TES temperature is above the temperature of heat energy flow $H_{`n7',`n8',t}$. In order to avoid non-linearities in the modeling, the maximum storage volume, $\overline{v_{tes}^{TES}}$, and the maximum charging/discharging capacity, $\overline{c_{tes}^{TES}}$, are determined exogenously. Table D.2 lists predefined combinations of maximum storage volumes and charging/discharging capacities that become available once the model makes an investment decision by means of the binary variable X_{tes}^{TES}.

$$TES_{tes,t}^{L} = \eta_{p,`TES',f} \cdot TES_{tes,t-1}^{L} + TES_{tes,t}^{C} - TES_{tes,t}^{D} \qquad \forall\, p, tes, f, t \qquad \text{(D.6a)}$$

$$TES_{tes,t}^{L} \leq \overline{TES^{L}}_{tes} = \overline{V_{tes}^{TES}} \cdot \rho \cdot c_w \cdot \left(\overline{\vartheta^{TES}} - \underline{\vartheta^{TR}}\right) \qquad \forall\, tes, t \qquad \text{(D.6b)}$$

$$TES_{tes,t}^{C} \leq \overline{C_{tes}^{TES}} \qquad \forall\, tes, t \qquad \text{(D.6c)}$$

$$TES_{tes,t}^{C} \leq X_{tes}^{TES,C} \cdot \overline{c_{tes}^{TES}} \qquad \forall\, tes, t \qquad \text{(D.6d)}$$

$$T_{`n1',`n2',t}^{T} \geq X_{tes,t}^{TES,C} \cdot \overline{\vartheta^{TES}} \qquad \forall\, tes, t \qquad \text{(D.6e)}$$

$$TES_{tes,t}^{C} \leq \overline{c_{tes}^{TES}} \cdot \frac{T_{`n1',`n2',t}^{T} - \overline{\vartheta^{TES}}}{\overline{\vartheta_{`n1',`n2'}^{DHS}} - \overline{\vartheta^{TES}}} + \left(1 - X_{tes,t}^{TES,C}\right) \cdot M \qquad \forall\, tes, t \qquad \text{(D.6f)}$$

$$TES_{tes,t}^{D} \leq \overline{C_{tes}^{TES}} \qquad \forall\, tes, t \qquad \text{(D.6g)}$$

$$TES_{tes,t}^{D} \leq \left(1 - X_{tes,t}^{TES,C}\right) \cdot \overline{c_{tes}^{TES}} \qquad \forall\, tes, t \qquad \text{(D.6h)}$$

$$TES_{tes,t}^{D} \leq \overline{c_{tes}^{TES}} \cdot \frac{\overline{\vartheta^{TES}} - T_{`n7',`n8',t}^{T}}{\overline{\vartheta^{TES}} - \underline{\vartheta^{TR}}} + X_{tes,t}^{TES,C} \cdot M \qquad \forall\, tes, t \qquad \text{(D.6i)}$$

$$\overline{V_{tes}^{TES}} = X_{tes}^{TES} \cdot \overline{v_{tes}^{TES}} \qquad \forall\, tes \qquad \text{(D.6j)}$$

$$\overline{C_{tes}^{TES}} = X_{tes}^{TES} \cdot \overline{c_{tes}^{TES}} \qquad \forall\, tes \qquad \text{(D.6k)}$$

Solar-to-heat constraints

The utilization of solar-thermal energy as a heat source in the district heating system faces two major technical constraints. First, enough solar radiation must be available for heat generation and second, the temperature level at the point of heat injection in the district heating network must be low enough. Both conditions must be met in order to make the most use of installed capacity. The following modeling aims to capture both effects. Constraint (D.7a), in conjunction with relation (D.7g), represents the investment decision in

Table D.2: TES tank volume and charging/discharging capacity.

	max. Volume	max. Capacity
$\boldsymbol{tes}$	$\overline{\boldsymbol{v}_{\boldsymbol{tes}}^{\boldsymbol{TES}}}$ $\mathbf{m^3}$	$\overline{\boldsymbol{c}_{\boldsymbol{tes}}^{\boldsymbol{TES}}}$ $\mathbf{MW_{th}}$
$tes1$	60,000	200
$tes2$	60,000	200
$tes3$	120,000	400
$tes4$	1,200,000	46.4
$tes5$	1,200,000	23.2
$tes6$	1,200,000	11.6
$tes7$	1,200,000	11.6

favor of solar-to-heat (S2H) capacity by means of the binary variable X_{s2h}^{S2H}. Constraints (D.7b) and (D.7c) model the extent to which an installed capacity, $\overline{c_{s2h,i}^{S2H}}$, can be exploited. Here, the heat generation capacity is modeled as an exogenously determined parameter in order to avoid non-linearities. In constraint (D.7c), parameter γ_t represents the intensity of solar radiation and varies between 0 and 1. If γ_t equals 1, the full capacity can be exploited in terms of the availability of solar radiation. If γ_t equals 0, the binary hourly operation decision variable $X_{s2h,t}^{S2H,C}$ is forced to be zero, which turns S2H generation, $Q_{s2h,i,t}^{S2H}$, to zero by means of constraint (D.7b). Nevertheless, even when γ_t equals 1, the temperature of heat energy flow $H_{`n5',`n6',t}$, that is $T_{`n5',`n6',t}^{T}$, must be lower than the maximum operation temperature, $\overline{\vartheta_{s2h,i}^{S2H}}$, of the S2H facility, in order to make use of this heat source. At best, γ_t equals 1 and $T_{`n5',`n6',t}^{T}$ equals $\underline{\vartheta^{TR}}$ in order to fully exploit the installed heat generation capacity. The time series of parameter γ_t is derived from hourly capacity factors available for power generation from PV according to relation (D.7d). Setting the non-negative parameter λ lower than 1 in this relation allows the modeler to manipulate the time series and renders the availability of solar radiation more favorable for S2H technology. Relations (D.7e) and (D.7f) aggregate the installed capacity and generation of S2H, respectively. Table D.3 lists the available capacity blocks. Moreover, they are attributed to two different technology qualities, S2H1 and S2H2. They differ in terms of their maximum operation temperature, here assumed at 120°C and 100°C, respectively. In a district heating network operating at high temperatures, a solar-thermal system with a higher maximum temperature would likely achieve greater capacity factors than a system with a lower maximum temperature. Certainly, this comes at higher investment costs, as assumed in Table 5.3. The binary investment decision variable X_{s2h}^{S2H} determines endogenously which of these

capacity blocks are available for solar-thermal heat generation.

$$Q^{S2H}_{s2h,i,t} \leq \overline{C^{S2H}_{s2h,i}} \qquad \forall\ s2h, i_{s2h}, t \qquad \text{(D.7a)}$$

$$Q^{S2H}_{s2h,i,t} \leq X^{S2H,C}_{s2h,t} \cdot \overline{c^{S2H}_{s2h,i}} \qquad \forall\ s2h, i_{s2h}, t \qquad \text{(D.7b)}$$

$$Q^{S2H}_{s2h,i,t} \leq \overline{c^{S2H}_{s2h,i}} \cdot \frac{\overline{\vartheta^{S2H}_{s2h,i}} \cdot \gamma_t - T^{T}_{\text{'n5','n6'},t}}{\overline{\vartheta^{S2H}_{s2h,i}} - \underline{\vartheta^{TR}}} + \left(1 - X^{S2H,C}_{s2h,t}\right) \cdot M \qquad \forall\ s2h, i_{s2h}, t \qquad \text{(D.7c)}$$

$$\gamma_t = \min\left(\frac{cf^{vRES}_{i,f,t}}{\max_{tt} cf^{vRES}_{i,f,tt}} \cdot \frac{1}{\lambda}; 1\right)_{|\{i \hat{=} \text{'}PV\text{'}; f \hat{=} \text{'}solar\text{'}\}} \qquad \forall\ t \qquad \text{(D.7d)}$$

$$\overline{Q}_{p,i,f} = \sum_{s2h} \overline{C^{S2H}_{s2h,i}} \qquad \forall\ p, i_{s2h}, f \qquad \text{(D.7e)}$$

$$Q_{p,i,f,t} = \sum_{s2h} Q^{S2H}_{s2h,i,t} \qquad \forall\ p, i_{s2h}, f, t \qquad \text{(D.7f)}$$

$$\overline{C^{S2H}_{s2h,i}} = X^{S2H}_{s2h} \cdot \overline{c^{S2H}_{s2h,i}} \qquad \forall\ s2h, i_{s2h} \qquad \text{(D.7g)}$$

Table D.3: Maximum capacities and maximum operation temperature of solar-thermal capacities (S2H).

s2h	**Technology** ***i***	**max. Capacity** $\overline{c^{S2H}_{s2h,i}}$ **MW$_{\text{th}}$**	**max. Operation temperature** $\overline{\vartheta^{S2H}_{s2h,i}}$ **°C**
s2h1	S2H1	10	120
s2h2	S2H1	20	120
s2h3	S2H1	30	120
s2h4	S2H2	10	100
s2h5	S2H2	20	100
s2h6	S2H2	30	100

D.3 Cost per unit of exergy (COPEX) production

$$\text{COPEX} = \frac{OC + FO\&MC + IC}{TEx^P + TEx^H} \tag{D.8a}$$

$$TEx^P = \sum_{p_B} \sum_{i} \sum_{f} \sum_{t} G_{p,i,f,t} - \sum_{t} D_t^{P2H^B} \tag{D.8b}$$

$$\begin{aligned} TEx^H = & \sum_{t} \left(1 - \frac{\vartheta^R + 273.15[K]}{T^T_{`n1',`n2',t} + 273.15[K]}\right) \cdot \left(\sum_{p} \sum_{f} \left(\sum_{i_{chp}} Q_{p,i,f,t} + \sum_{i_{DHB}} Q_{p,i,f,t}\right.\right. \\ & \left.\left. + \sum_{i_{DHEB}} \eta_{p,i,f} \cdot G_{p,i,f,t}\right) + \alpha \cdot X_t^T \cdot d_t^{PW}\right) \\ & + \sum_{t} \left(1 - \frac{\vartheta^R + 273.15[K]}{T^T_{`n1',`n2',t} + 273.15[K]}\right) \end{aligned} \tag{D.8c}$$

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